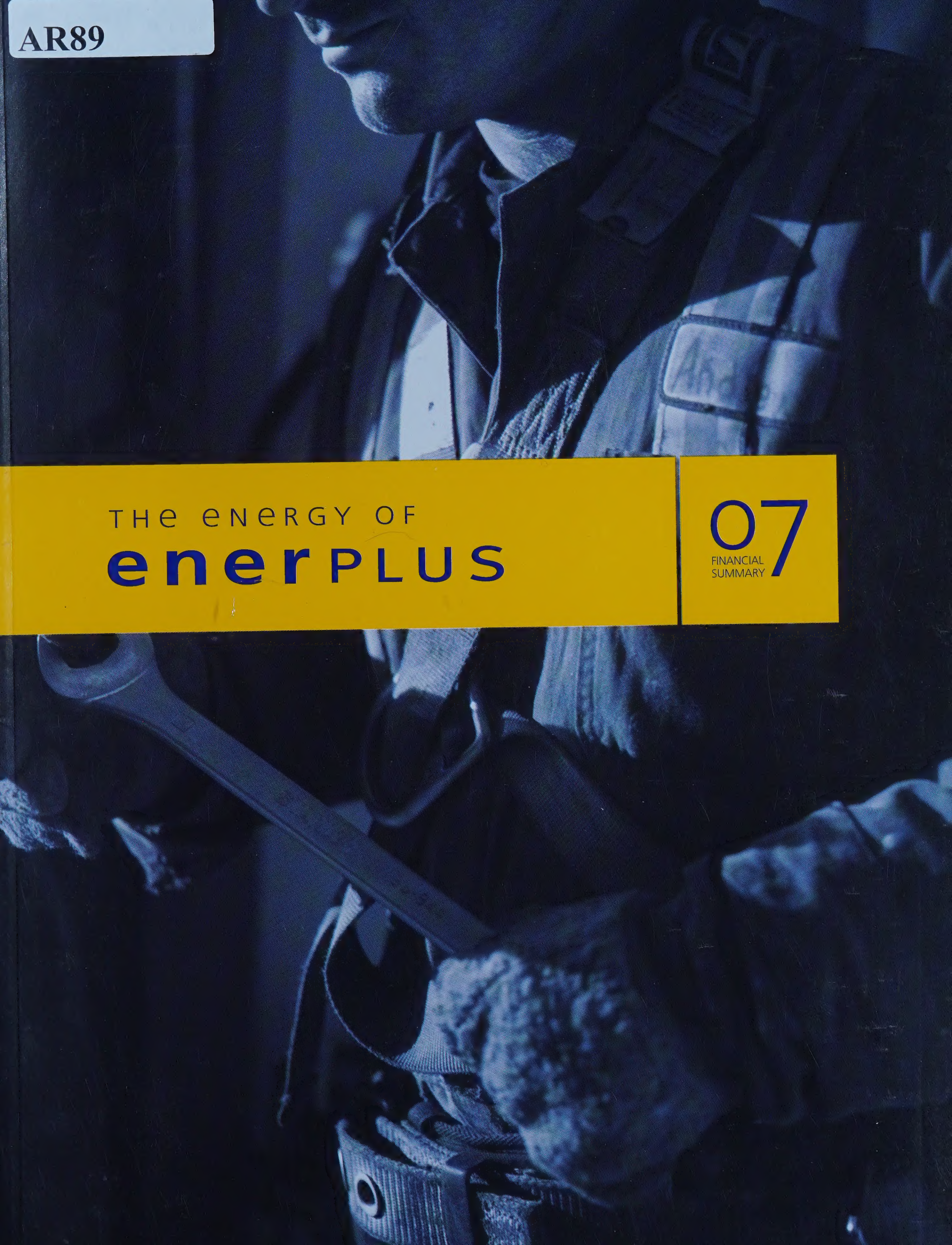


THE ENERGY OF

enerPLUS

07
FINANCIAL SUMMARY

CORPORATE PROFILE

Enerplus is a high-yielding equity investment in the oil and natural gas business. We are one of Canada's oldest and largest independent oil and gas producers established in 1986. We have built a balanced and diversified portfolio of producing properties across western Canada and the United States with a focus on large resource plays that offer predictable production and repeatable, low-risk development opportunities in conventional oil and gas production as well as in Canada's oil sands. Enerplus creates value through development drilling, optimization and acquisitions that enhance the sustainability of our business over the long-term. Through our discipline of paying a significant portion of our cash flow to investors each month, we believe we offer an attractive investment in the oil and gas industry.

management's discussion and analysis ("md&a")

The following discussion and analysis of financial results is dated February 27, 2008 and is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2007 and 2006. All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. In addition to disclosing reserves under the requirements of NI 51-101, we also disclose our reserves on a company interest basis which is not a term defined under NI 51-101. This information may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our disclaimer on forward-looking information and statements.

Non-GAAP Measures

Throughout the MD&A we use the term "payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows. The term "payout ratio" does not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities.

Refer to the Liquidity and Capital Resources section of the MD&A for further information on cash flow, cash distributions and payout ratio.

2007 Overview

Cash flow from operating activities totaled $868.5 million in 2007, essentially flat over 2006. Higher realized crude oil prices, cash gains generated from our price risk management program and a decrease in our non-cash working capital helped to mitigate the impact of lower production, reduced natural gas prices and increased operating costs. Monthly cash distributions remained constant at $0.42 per trust unit throughout 2007 for an annual total of $5.04 per trust unit.

Our 2007 development capital spending totaled $387.2 million, resulting in the drilling of 252 net wells with a 99% success rate. On January 31, 2007 we acquired gross-overriding royalty interests in the Jonah natural gas field in Wyoming U.S. ("Jonah") for approximately $61 million. In the second quarter we acquired the Kirby Oil Sands Partnership ("Kirby"), an operated Steam Assisted Gravity Drainage ("SAGD") project, for $203.1 million ($148.3 million in cash and $54.8 million in equity). An equity offering consisting of 4.25 million trust units for gross proceeds of $210.6 million was also completed in conjunction with the Kirby acquisition.

During 2007 production averaged 82,319 BOE/day, in-line with our third quarter guidance of 82,500 BOE/day and 4% below our 2006 production of 85,779 BOE/day. Reduced development capital spending, unplanned downtime, lower initial production rates on our third well per section Bakken oil wells and natural reservoir declines are the primary reasons for the decrease.

On June 22, 2007 the Federal Government enacted a new tax on publicly traded income trusts and limited partnerships (specified investment flow-through entities, or "SIFTs") effective January 1, 2011. As a result we recorded a $78.1 million future income tax expense. We are currently evaluating alternatives to determine the optimal structure for Enerplus post 2010 to maximize the return to investors. However, we see value in the remaining three-year tax exemption period through 2010 and currently look to maintaining our current structure during this period unless there are compelling reasons to change. In the

fourth quarter of 2007 the Alberta Government also announced proposed changes to the provincial royalty program effective January 1, 2009 which have not yet been enacted into law.

On February 13, 2008 we successfully closed the largest transaction in our 22 year history, acquiring Focus Energy Trust ("Focus") for total consideration of $1.7 billion including approximately $340 million of assumed debt. Under the plan of arrangement, Focus unitholders received 0.425 of an Enerplus trust unit for each Focus trust unit. We believe the combined entity is well positioned for future growth with a strong balance sheet and production expected to be approximately 98,000 BOE/day in 2008.

Highlights

- Cash flow from operating activities totaled $868.5 million in 2007, essentially flat over 2006.
- Distributions have remained constant at $0.42 per trust unit for the past 28 months resulting in annual cash distributions of $5.04 per trust unit.
- Net income totaled $339.7 million, a decrease of $205.1 million from 2006.
- Our payout ratio increased slightly to 74% from 71%.
- Our price risk management program realized cash gains of $13.6 million or $0.45/BOE on our commodity financial contracts, an increase compared to cash losses of $34.3 million or $1.10/BOE in 2006.
- General and Administrative ("G&A") expenses were $2.26/BOE, 6% lower than our guidance of $2.40/BOE and 18% higher than $1.91/BOE in 2006.
- Operating costs were $9.12/BOE for 2007, slightly below our third quarter guidance of $9.20/BOE and a year-over-year increase of 14%.

- On January 31, 2007 we acquired an overriding royalty interest in the Jonah field in Wyoming for total consideration of approximately $61.0 million.
- In the second quarter we acquired Kirby for a total purchase price of $203.1 million, consisting of $148.3 million in cash and $54.8 million in equity.
- In conjunction with the Kirby acquisition, on April 10, 2007 an equity offering was completed consisting of 4.25 million trust units raising gross proceeds of $210.6 million.

- Our development capital spending of $387.2 million was in-line with our guidance of $390.0 million and resulted in drilling of 252 net wells with a 99% success rate.
- Production averaged 82,319 BOE/day, in-line with our third quarter guidance of 82,500 BOE/day.
- Our proved plus probable finding, development and acquisition costs ("FD&A") costs on our conventional oil and gas activities were $19.79/BOE for the year and when we include our oil sands activities, FD&A costs were $27.69/BOE.
- Reserve additions from development capital spending and acquisitions replaced 90% of 2007 production on a proved plus probable basis and 67% on a proved basis.
- Our conventional recycle ratio (operating income divided by FD&A) was 1.5x on a three-year basis and 1.6x for 2007 using proved plus probable reserves.
- We added 6.8 million barrels of probable reserves relating to our Joslyn steam assisted gravity drainage project.
- Proved plus probable reserves decreased 1% to 440.2 MMBOE and proved reserves decreased 3% to 289.9 MMBOE.

- Our Reserve Life Index ("RLI") continued to be one of the longest in the sector at 14.8 years on a proved plus probable basis and 10.3 years on a proved basis, including both conventional and non-conventional reserves.
- On February 13, 2008 we acquired Focus creating an entity with a combined market capitalization of approximately $7.6 billion.
- In conjunction with the Focus acquisition we increased our bank credit facility from $1.0 billion to $1.4 billion on February 13, 2008.
- We continue to maintain a conservative balance sheet with a net debt to trailing 12 month cash flow ratio of 0.8x at December 31, 2007.

Results of Operations

Production

Production during 2007 averaged 82,319 BOE/day, in-line with our third quarter guidance of 82,500 BOE/day and 4% lower than 85,779 BOE/day in 2006. Our 2007 production was impacted by the fact that we spent $104 million or 21% less development capital than the prior year. In addition we experienced unexpected down time and turn-around activities at partner operated facilities. Our third well per section program at our U.S. Bakken property had lower initial production rates than originally forecast; however the program continues to deliver attractive economics and reserves. These decreases were partially offset by production from our acquisition of Jonah that closed January 31, 2007.

Average production during the year was weighted 53% to natural gas and 47% to liquids on a BOE basis. Average production volumes for the years ended December 31, 2007 and 2006 are outlined below:

Daily Production Volumes	2007	2006	% Change
Natural gas (Mcf/day)	262,254	270,972	(3)%
Crude oil (bbls/day)	34,506	36,134	(5)%
Natural gas liquids (bbls/day)	4,104	4,483	(8)%
Total daily sales (BOE/day)	82,319	85,779	(4)%

We exited the year with production of approximately 79,800 BOE/day based on December's average production rate, 4% below our exit target of 83,000 BOE/day. Approximately 2,000 BOE/day of the decrease related to a previously announced fire that occurred at our Giltedge property on November 30, 2007. We expect production from this property to be back on-line by mid-2008. We have both business interruption insurance and property insurance which we anticipate will mitigate the majority of these losses. The remainder of the 1,200 BOE/day difference related to tie-in delays primarily on non-operated capital projects at year end and pipeline problems at our non-operated Mitsue property.

Considering our acquisition of Focus that closed on February 13, 2008 and our current development capital program, we expect 2008 annual production volumes to average 98,000 BOE/day, weighted 60% to natural gas and 40% to liquids. We expect to exit 2008 with production of approximately 100,000 BOE/day. This guidance does not contemplate any other potential acquisitions or dispositions.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for 2007 with those of 2006. It also compares the benchmark price indices for the same periods.

Average Selling Price[1]	2007	2006	% Change
Natural gas (per Mcf)	$ 6.45	$ 6.81	(5)%
Crude oil (per bbl)	$65.11	$61.80	5 %
Natural gas liquids (per bbl)	$51.35	$50.90	1 %
Per BOE	$50.48	$50.23	– %

[1] Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

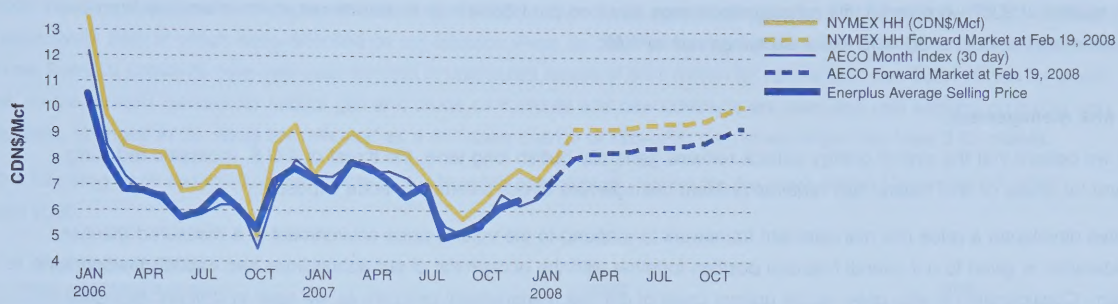
Average Benchmark Pricing	2007	2006	% Change
AECO natural gas – monthly index (CDN$/Mcf)	$ 6.61	$ 6.99	(5)%
AECO natural gas – daily index (CDN$/Mcf)	$ 6.45	$ 6.53	(1)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	$ 6.92	$ 7.26	(5)%
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	$ 7.44	$ 8.25	(10)%
WTI crude oil (US$/bbl)	$72.34	$66.22	9 %
WTI crude oil: CDN$ equivalent (CDN$/bbl)	$77.78	$75.25	3 %
CDN$/US$ exchange rate	0.93	0.88	6 %

Natural Gas

Natural gas prices started 2007 in a weak position due to a mild December 2006. However cold weather across key consuming regions of the United States from the latter part of January 2007 through to March resulted in increased prices. Early forecasts for an active hurricane season led to an expectation that strong prices would carry into and through the summer. However, this past year marked a changing dynamic in global liquefied natural gas ("LNG") trade, with cargos more readily shifting between Asia, Europe, and North America depending on spot market prices and access to storage. Accordingly, low demand in Europe pushed significant volumes of LNG to North America from March through August. This LNG, along with continued strong North American production, resulted in high U.S. and Canadian storage balances by the end of the summer which depressed prices. Natural gas prices during the year traded within a band that saw highs of approximately $8.00/Mcf during the winter and lows of around $5.00/Mcf at the end of the summer injection season. This was a narrower band than was experienced during 2006 where natural gas prices fluctuated between $12.00/Mcf and $4.00/Mcf.

Our natural gas portfolio in 2007 was comprised of aggregator, AECO, and downstream direct sales. In 2007 we sold 40% of our natural gas on the daily AECO market and 40% on the monthly AECO market, as well as 20% against the day and month NYMEX indices. During 2007 we realized an average price for our natural gas sales of $6.45/Mcf (net of transportation costs), a decrease of 5% from $6.81/Mcf realized in 2006. This reduction is comparable to the price decreases realized in each of: the AECO monthly index which decreased by 5%; the AECO daily index which decreased by 1%; and the NYMEX monthly index (converted to CDN$/Mcf) which decreased by 10%.

Natural Gas Prices

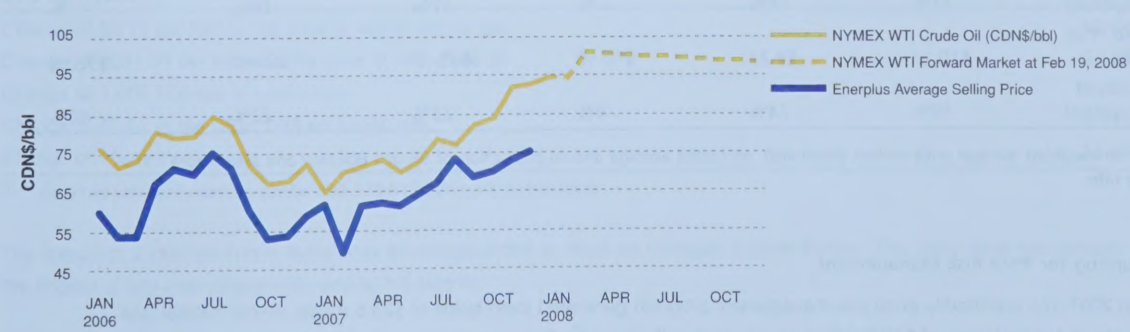


Crude Oil

Crude prices were weak in the first quarter of 2007, with a low of US$50.48/bbl. Prices rose steadily through the remaining months reaching a high of US$98.18/bbl in mid November. In terms of market fundamentals, OPEC kept its supply constant, non-OPEC production was lower than expected and growth demands in Asia remained strong. As a result, global crude and refined product inventories declined. In addition there was growing concern global production was reaching its peak. These fundamentals placed steady upward pressure on crude oil prices through the year.

Our crude oil portfolio in 2007 was approximately 74% light/medium and 26% heavy. The average price received for our crude oil (net of transportation costs) was CDN$65.11/bbl during 2007, a 5% increase over 2006. The West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, increased 3% year-over-year. On average for 2007, the slight narrowing of the light to heavy differential had a positive effect on our overall crude oil and gas sales. However, in the fourth quarter of 2007, and in particular in December, absolute heavy oil differentials to WTI widened significantly due to a number of factors, including: outages of refineries with heavy oil conversion capabilities; drawdown of inventories prior to year end; and operational issues on key intra-Alberta and export pipelines. These differentials reverted to historical levels in January 2008.

Crude Oil Prices



The Canadian dollar opened 2007 at an exchange rate of $0.86/US$ and strengthened throughout the year hitting a high in November of $1.09/US$ and ending the year at $0.99/US$. On average it strengthened 6% against the U.S. dollar during 2007 compared to 2006 based on the annual average exchange rate. As most of our crude oil and a portion of our natural gas are priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

Historically we have not attempted to hedge against fluctuations in the foreign exchange value of our oil and gas sales. In the fourth quarter of 2007 we entered into a foreign exchange swap on our US$54 million debentures which effectively fixed the principal repayments at a CDN/US dollar exchange rate of 1.02.

Price Risk Management

While we believe that the overall energy outlook remains generally bullish long term, the threat of a U.S. recession reducing demand for crude oil and natural gas requires prudent management of our commodity price exposure.

We have developed a price risk management framework to respond to the volatile price environment in a measured manner. Consideration is given to our overall financial position together with the economics of our acquisitions and capital development program. Consideration is also given to the upfront costs of our risk management program as we seek to limit our exposure to price downturns and maintain participation in upside potential should commodity prices increase.

Consistent with our price risk management framework, we entered into additional commodity contracts during the fourth quarter of 2007 and during the first quarter of 2008. These contracts are designed to protect a portion of our natural gas sales for the period January 2008 through March 2009 and to protect a portion of our crude oil sales for the period January 2008 through December 2009. We have also hedged electricity volumes for the period January 2008 through December 2009 to protect against rising electricity costs in the Alberta power market. See Note 12 for a detailed list of our current price risk management positions including positions we assumed through the Focus acquisition.

The following is a summary of the financial contracts in place at February 20, 2008, including positions entered into by Focus, expressed as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)		
	January 1, 2008 – March 31, 2008	April 1, 2008 – October 31, 2008	November 1, 2008 – March 31, 2009	January 1, 2008 – June 30, 2008	July 1, 2008 – December 31, 2008	January 1, 2009 – December 31, 2009
Floor Prices (puts)	$ 8.28	$7.06	$ 8.18	$70.91	$72.09	$77.63
% (net of royalties)	18%	24%	4%	35%	35%	10%
Fixed Price (swaps)	$ 8.73	$7.16	$ –	$79.95	$79.97	$ –
% (net of royalties)	11%	16%	– %	17%	19%	– %
Capped Price (calls)	$10.12	$8.22	$10.10	$85.09	$85.48	$92.98
% (net of royalties)	19%	24%	4%	23%	22%	10%

Based on weighted average price (before premiums), estimated average annual production of 98,000 BOE/day and assuming a 19% royalty rate.

Accounting for Price Risk Management

During 2007, our commodity price risk management program generated cash gains of $23.6 million on our natural gas contracts and cash losses of $10.0 million on our crude oil contracts. The natural gas cash gains are due to contracts in place during 2007 that provided floor protection as the price of natural gas declined. The crude oil cash losses are due to crude oil prices rising above our swap positions. In comparison, our 2006 commodity price risk management program resulted in cash losses of $7.1 million on our natural gas contracts and $27.2 million on our crude oil contracts.

At December 31, 2007 the fair value of our natural gas and crude oil derivative instruments, net of premiums, represents a gain of $9.7 million and a loss of $52.5 million, respectively. The natural gas gain is recorded as a current deferred financial asset on

our balance sheet and the crude oil loss is recorded as a current deferred financial credit. In comparison, at December 31, 2006 the fair value of our natural gas and crude oil derivative instruments represented gains of $12.7 million and $10.9 million respectively, both of which were recorded on our balance sheet as deferred financial assets. The change in the fair value of these financial contracts year-over-year resulted in unrealized losses of $3.0 million for natural gas and $63.4 million for crude oil. As the forward markets for natural gas and crude oil fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or non-cash gain in earnings. See Note 3 for details.

The following table summarizes the effects of our financial contracts on income for the years ended December 31, 2007 and 2006.

Risk Management Costs

($ millions, except per unit amounts)	2007		2006	
Cash gains/(losses):				
Natural gas	$ 23.6	$ 0.25/Mcf	$ (7.1)	$(0.07)/Mcf
Crude oil	(10.0)	$(0.79)/bbl	(27.2)	$(2.06)/bbl
Total cash gains/(losses)	$ 13.6	$ 0.45/BOE	$(34.3)	$(1.10)/BOE
Non-cash (losses)/gains on financial contracts:				
Change in fair value – natural gas	$ (3.0)	$(0.03)/Mcf	$ 50.6	$ 0.51/Mcf
Change in fair value – crude oil	(63.4)	$(5.03)/bbl	30.4	$ 2.30/bbl
Amortization of deferred financial assets	–	$ – /BOE	(49.9)	$(1.59)/BOE
Total non-cash (losses)/gains	$(66.4)	$(2.21)/BOE	$ 31.1	$ 0.99/BOE
Total (losses)	$(52.8)	$(1.76)/BOE	$ (3.2)	$(0.11)/BOE

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts as described in Note 12 (including those entered into by Focus) and are based on 2008 forward markets as at February 20, 2008. To the extent the market price of crude oil and natural gas change significantly from current levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on 2008 Cash Flow per Trust Unit(1)
Change of $0.15 per Mcf in the price of AECO natural gas	$0.08
Change of US$1.00 per barrel in the price of WTI crude oil	$0.06
Change of 1,000 BOE/day in production	$0.10
Change of $0.01 in the US$/CDN$ exchange rate	$0.12
Change of 1% in interest rate	$0.07

(1) Assumes constant working capital and 129,813,000 units outstanding.

The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

Revenues

Crude oil and natural gas revenues for the year ended December 31, 2007 were $1,517.1 million ($1,539.2 million, net of $22.1 million of transportation costs), a decrease of 4% or $55.6 million compared to $1,572.7 million ($1,595.3 million, net of $22.6 million of transportation costs) during 2006. Decreased production and lower natural gas prices were partially offset by an increase in realized crude oil prices.

Analysis of Sales Revenue[1] ($ millions)	Crude oil	NGLs	Natural Gas	Total
2006 Sales Revenue	$815.0	$83.3	$674.4	$1,572.7
Price variance[1]	41.8	0.7	(33.8)	8.7
Volume variance	(36.7)	(7.1)	(20.5)	(64.3)
2007 Sales Revenue	**$820.1**	**$76.9**	**$620.1**	**$1,517.1**

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Royalties in 2007 and 2006 were approximately 19% of oil and gas sales, net of transportation costs. Overall, royalties decreased marginally in 2007 to $285.1 million compared to $296.6 million during 2006 primarily as a result of the decrease in natural gas revenue experienced over the period.

We expect royalties to be approximately 19% of oil and gas sales, net of transportation costs for 2008.

Alberta Royalty Review

On October 25, 2007 the Alberta government announced the 'New Royalty Framework' ("NRF"), an updated royalty regime proposed to be effective January 1, 2009 which is intended to increase Government royalty revenue by 20%. On conventional oil and gas production during 2007, Alberta Crown royalties were $122.1 million (43%) of our total royalties. Based on this royalty rate and in the context of our production and pricing experienced during 2007, we estimate that the NRF would have increased the royalties on our conventional production by approximately $15 to $20 million. The acquisition of Focus in 2008 will help to mitigate the effects of the Alberta royalty review as the production from Focus is concentrated in Saskatchewan and British Columbia.

The moderate royalty increase is a reflection of the NRF's sensitivity to our portfolio, which includes lower productivity wells combined with the low natural gas prices experienced in 2007. It is important to note that this context may not be indicative of the environment in 2009 when the NRF comes into effect. The fundamental design of the new Alberta regime (which increases royalty rates as commodity prices increase) has removed some of the price upside producers had previously factored into their risk assessments for capital investment. As a result, Alberta will not be as attractive to invest in as other jurisdictions that allow greater participation in price upside.

The Alberta government is currently working with industry to address "unintended consequences" of economic issues related to the NRF and as at the date of this MD&A the Alberta government had not yet made the necessary legislative and administration changes to implement the NRF. The NRF announcement can be found on the Alberta government's website at www.gov.ab.ca.

Operating Expenses

Operating expenses during 2007 were $9.12/BOE or $274.2 million, representing a 1% decrease from our third quarter guidance of $9.20/BOE and a 14% increase from $8.02/BOE in 2006. Operating expenses for the year were lower than our guidance primarily due to lower than expected electricity charges during the fourth quarter. The increase in operating costs over 2006 was due to the combination of increased labour, well servicing, and repairs and maintenance costs along with lower

production volumes during 2007. A field training initiative in 2007 directed at optimizing production and reducing the time required to drill, complete and bring new wells on stream also contributed to the year-over-year increase.

By combining the lower cost operating expenses associated with the Focus properties we expect operating costs for 2008 to average $8.65/BOE, representing a decrease of 5% per BOE compared to 2007.

General and Administrative Expenses ("G&A")

G&A expenses were $2.26/BOE or $67.9 million for the year ended December 31, 2007, approximately 6% lower than our guidance of $2.40/BOE and 18% higher than $1.91/BOE in 2006. G&A expenses were lower than our guidance primarily due to lower than anticipated long term cash compensation charges related to our performance trust unit plan ("PTU") which is impacted by our trust unit price. The increase in general and administrative costs over 2006 was mainly due to increased overall salary and benefits as a result of continued wage inflation, increased staff and lower production volumes during 2007.

For the year ended December 31, 2007 our G&A expenses included non-cash charges for our trust unit rights incentive plan of $8.4 million or $0.28/BOE compared to $6.3 million or $0.20/BOE for 2006. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. The volatility of our trust unit price combined with the increased number of rights outstanding associated with additional employees increased the non-cash cost of the plan. Although non-cash charges have increased as a result of the option pricing model, the proportion of rights that are "in-the-money" has decreased in comparison with 2006. See Note 10 for further details.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs ($ millions)	2007	2006
Cash	$59.5	$53.6
Trust unit rights incentive plan (non-cash)	8.4	6.3
Total G&A	$67.9	$59.9

(Per BOE)	2007	2006
Cash	$1.98	$1.71
Trust unit rights incentive plan (non-cash)	0.28	0.20
Total G&A	$2.26	$1.91

In 2008 we expect total G&A costs to decrease slightly to approximately $2.20/BOE, including non-cash G&A costs of approximately $0.20/BOE.

Interest Expense

With the adoption of the new accounting standards on January 1, 2007 interest expense includes interest on long-term debt, the premium amortization on our US$175 million senior unsecured notes, unrealized gains and losses resulting from the change in fair value of our interest rate swaps as well as the interest component on our cross currency interest rate swap (see Note 8).

Interest on long-term debt during 2007 totaled $41.9 million, a $9.7 million increase from $32.2 million in 2006. The increase was due to higher average indebtedness and a higher weighted average interest rate of 5.1% during 2007 compared to 4.8% in 2006.

The following table summarizes the cash and non-cash interest expense recorded.

Interest Expense ($ millions)	2007	2006
Interest on long-term debt	$41.9	$32.2
Unrealized gain	(8.3)	–
Total Interest Expense	$33.6	$32.2

At December 31, 2007 approximately 18% of our debt was based on fixed interest rates while 82% had floating interest rates.

Capital Expenditures

During 2007 we spent $387.2 million on development capital and facilities, which is $104.0 million or 21% less than 2006. Spending in 2007 was in-line with our guidance of $390.0 million. Development capital spending was lower in 2007 as we spent less on natural gas development due to decreasing natural gas prices and increasing drilling and servicing costs. Development in 2007 focused primarily on Bakken oil and waterfloods. We achieved a 99% success rate with our drilling program on 252 net wells drilled during 2007.

Property acquisitions were $274.2 million during 2007 compared to $51.3 million in 2006. The majority of our 2007 acquisitions related to the purchase of Kirby for total consideration of $203.1 million and the purchase of gross-overriding royalty interests in the Jonah area for approximately $61.0 million. Property dispositions were $9.6 million during 2007 compared to $21.1 million in 2006. Our 2007 divestments included $5.6 million of property interests in the Thorhild area and the sale of 36,000 net acres of undeveloped land in North Dakota for approximately $3.6 million. Divestments in 2006 primarily related to the $19.7 million sale of a 1% working interest in the Joslyn property.

Capital Expenditures ($ millions)	2007	2006
Development expenditures	$321.3	$380.5
Plant and facilities	65.9	110.7
Development Capital	387.2	491.2
Office	6.5	5.0
Sub-total	393.7	496.2
Acquisitions of oil and gas properties[1]	274.2	51.3
Dispositions of oil and gas properties[1]	(9.6)	(21.1)
Total Net Capital Expenditures	$658.3	$526.4
Total Capital Expenditures financed with cash flow	$221.7	$249.4
Total Capital Expenditures financed with debt and equity	443.2	296.5
Total non-cash consideration for property dispositions	(6.6)	(19.5)
Total Net Capital Expenditures	$658.3	$526.4

(1) Net of post-closing adjustments.

The following is a summary by play type of our development capital expenditures during 2007 and 2006, as well as our current expectations for 2008 including Focus.

Play Type ($ millions)	2008 Estimate	2007	2006
Shallow Gas and CBM	$128	**$ 39.3**	$ 94.0
Crude Oil Waterfloods	105	**54.2**	66.0
Deep Tight Gas	53	**34.7**	34.1
Bakken Oil	47	**106.2**	116.7
Other Conventional Oil and Gas	142	**113.9**	141.3
Oil Sands	105	**38.9**	39.1
Total	$580	**$387.2**	$491.2

We currently expect total development capital expenditures in 2008 to be approximately $580 million. Conventional development capital is presently anticipated to be approximately $475 million with a slight bias to oil related projects over natural gas projects. Oil sands development capital is currently projected to be approximately $105 million.

Oil Sands

Our Joslyn and Kirby development projects have not commenced commercial production. As a result all associated costs, net of revenues generated, are capitalized and excluded from our depletion calculation. During 2007 we capitalized costs of $35.2 million on Joslyn and $205.4 million on Kirby, inclusive of acquisition costs, development capital spending, salaries and benefits, engineering and planning. At December 31, 2007 capitalized costs life-to-date for Joslyn were $116.4 million and for Kirby were $205.4 million for a combined total of $321.8 million.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the year ended December 31, 2007 DDA&A of $15.43/BOE is comparable to $15.38/BOE during the year ended December 31, 2006.

No impairment existed at December 31, 2007 using year-end reserves and management's estimates of future prices. Our future price estimates are more fully discussed in Note 4.

Asset Retirement Obligations

We have estimated our total future asset retirement obligations based on our net ownership interest in wells and facilities, along with the estimated cost and timing to abandon and reclaim wells and facilities in future periods. Our asset retirement obligation was $165.7 million at December 31, 2007 compared to $123.6 million at December 31, 2006. The majority of the $42.1 million increase was due to increased cost estimates as a result of enhanced regulatory requirements on abandonment and reclamation activities. The remainder of the change was due to retirement costs incurred, offset by accretion expense for the year. See Note 5 for further details.

The following chart compares the amortization of the asset retirement cost, accretion of the asset retirement obligation, and asset retirement obligations settled.

($ millions)	2007	2006
Amortization of the asset retirement cost	**$11.4**	$12.6
Accretion of the asset retirement obligation	**6.7**	6.2
Total Amortization and Accretion	**$18.1**	$18.8
Asset Retirement Obligations Settled	**$16.3**	$11.5

Actual asset retirement costs are incurred at different times compared to the recording of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2038 and 2047. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Canadian Government's tax changes

On June 22, 2007 Bill C-52, which contained legislative provisions to implement the proposals to tax publicly traded income trusts in Canada became law. As a result, our second quarter future income tax provision included a future income tax expense of $78.1 million related to this legislation. This non-cash expense related to temporary differences between the accounting and tax basis of the Fund's assets and liabilities at that time and had no immediate impact on cash flow.

On December 14, 2007, Bill C-28, which contained legislative provisions to implement corporate income tax rate reductions announced in the October 30, 2007 fall economic statement, became law. The general corporate tax rate will decrease by 1.0% in 2008 from 20.5% to 19.5%. There are additional rate reductions scheduled until the target federal tax rate of 15.0% is reached as of January 1, 2012. These rate reductions will also apply to the SIFT tax on income trusts. As a result, our fourth quarter future income tax provision includes a future income tax recovery of $22.6 million related to this legislation.

Future Income Taxes

Future income taxes arise from differences between the accounting and tax basis of assets and liabilities. A portion of the future income tax liability that is recorded on the balance sheet will be recovered through earnings before 2011. The balance will be realized when future income tax assets and liabilities are realized or settled.

As a result of the SIFT tax, all entities within our organization are now subject to future income taxes whereas prior to the SIFT tax enactment only incorporated entities in our organization were subject to future income taxes. As a result our future income tax recovery was $1.0 million for the year ended December 31, 2007 compared to a recovery of $112.0 million for the same period in 2006. The changes in future income taxes compared to 2006 are primarily a result of the following:

- The SIFT tax resulted in a future income tax expense of $78.1 million in the second quarter of 2007; and
- Corporate income tax rate changes enacted during the year have resulted in a year-to-date future tax recovery of $22.6 million compared to a $35.5 million recovery in 2006.

After consideration of the above items, the future income tax provisions were comparable between the periods.

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund which ultimately transfers both income and future income tax liability to our unitholders. As a result, no cash income taxes have been paid by our Canadian operating entities. However, effective January 1, 2011 we will be subject to the SIFT tax should we remain a trust.

The amount of current taxes recorded throughout the year on our U.S. operations is dependent upon the timing of both capital expenditures and repatriation of the funds to Canada. Our U.S. taxes as a percentage of cash flow, assuming constant working capital, were 11% in 2007 compared to our guidance of 10%. We expect the current income and withholding taxes to average approximately 20% of cash flow from U.S. operations in 2008 based on our current development capital program and assuming all funds are repatriated to Canada after U.S. development capital spending. The increase for 2008 is a result of plans for reduced development capital spending in the U.S. during the year.

During 2007 our U.S. operations incurred income related taxes in the amount of $23.0 million compared to $18.2 million in 2006. The increase in current taxes is due to an increase in net income combined with a modest decrease in drilling and completion expenditures for the year.

Tax Pools

We estimate our tax pools at December 31, 2007 to be as follows:

Pool Type ($ millions)	**Trust**	**Operating Entities**	**Total**
COGPE	$470	$ 100	$ 570
CDE	–	340	340
UCC	–	600	600
Tax losses and other	30	600	630
Foreign tax pools	–	140	140
Total	$500	$1,780	$2,280

We acquired approximately $200 million in tax pools related to the Focus acquisition (net of any pools required to offset partnership deferrals).

Net Income

Net income in 2007 was $339.7 million or $2.66 per trust unit compared to $544.8 million or $4.48 per trust unit in 2006. The $205.1 million decrease in net income was primarily due to a $111.0 million decrease in future income tax recovery, a $49.6 million increase in cash and non-cash risk management costs, a $55.6 million decrease in oil and gas sales (net of transportation costs) and a $22.9 million increase in operating costs, partially offset by an increase in other income of $12.5 million and decreased DDA&A charges of $17.9 million.

Cash Flow from Operating Activities

Cash flow from operating activities in 2007 was $868.5 million or $6.80 per trust unit compared to $863.7 million or $7.10 per trust unit in 2006. The decrease on a per unit basis is largely due to the April 2007 equity offering, which was primarily used to purchase Kirby, a development project that is not currently generating cash flow.

Selected Financial Results

Per BOE of production (6:1)	Year Ended December 31, 2007 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total	Year Ended December 31, 2006 Operating Cash Flow[(1)]	Non-Cash & Other Items	Total
Production per day			82,319			85,779
Weighted average sales price[(2)]	$50.48	$ –	$ 50.48	$50.23	$ –	$ 50.23
Royalties	(9.49)	–	(9.49)	(9.47)	–	(9.47)
Commodity derivative instruments	0.45	(2.21)	(1.76)	(1.10)	0.99	(0.11)
Operating costs	(9.11)	(0.01)	(9.12)	(8.02)	–	(8.02)
General and administrative	(1.98)	(0.28)	(2.26)	(1.71)	(0.20)	(1.91)
Interest expense, net of interest income	(1.37)	0.28	(1.09)	(0.95)	–	(0.95)
Foreign exchange gain/(loss)	(0.06)	0.30	0.24	0.02	–	0.02
Current income tax	(0.77)	–	(0.77)	(0.59)	–	(0.59)
Restoration and abandonment cash costs	(0.54)	0.54	–	(0.37)	0.37	–
Depletion, depreciation, amortization and accretion	–	(15.43)	(15.43)	–	(15.38)	(15.38)
Future income tax (expense)/recovery	–	0.04	0.04	–	3.58	3.58
Marketable securities[(3)]	–	0.47	0.47	–	–	–
Total per BOE	$27.61	$(16.30)	$ 11.31	$28.04	$(10.64)	$ 17.40

(1) Cash Flow from Operating Activities before changes in non-cash operating working capital.

(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

(3) In addition to non-cash shares of marketable securities, a gain on sale of marketable securities was a cash item; however the cash item is included in cash flow from investing activities not cash flow from operating activities.

Selected Annual Canadian and U.S. Financial Results

The following table provides a geographical analysis of key operating and financial results for 2007 and 2006.

	Year Ended December 31, 2007			Year Ended December 31, 2006		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	251,561	10,693	262,254	265,019	5,953	270,972
Crude oil (bbls/day)	24,590	9,916	34,506	25,858	10,276	36,134
Natural gas liquids (bbls/day)	4,104	–	4,104	4,483	–	4,483
Total daily sales (BOE/day)	70,621	11,698	82,319	74,511	11,268	85,779
Pricing(1)						
Natural gas (per Mcf)	$ 6.45	$ 6.55	$ 6.45	$ 6.79	$ 7.78	$ 6.81
Crude oil (per bbl)	$ 62.27	$72.17	$ 65.11	$ 59.36	$67.93	$ 61.80
Natural gas liquids (per bbl)	$ 51.35	$ –	$ 51.35	$ 50.90	$ –	$ 50.90
Capital Expenditures						
Development capital and office	$ 287.3	$106.4	$ 393.7	$ 378.5	$117.7	$ 496.2
Acquisitions of oil and gas properties	$ 213.3	$ 60.9	$ 274.2	$ 35.3	$ 16.0	$ 51.3
Dispositions of oil and gas properties	$ (6.0)	$ (3.6)	$ (9.6)	$ (21.1)	$ –	$ (21.1)
Revenues						
Oil and gas sales(1)	$1,230.4	$286.7	$1,517.1	$1,301.0	$271.7	$1,572.7
Royalties	$ (226.4)	$ (58.7)(2)	$ (285.1)	$ (244.4)	$ (52.2)(2)	$ (296.6)
Commodity derivative instruments	$ (52.8)	$ –	$ (52.8)	$ (3.2)	$ –	$ (3.2)
Expenses						
Operating	$ 264.4	$ 9.8	$ 274.2	$ 243.8	$ 7.4	$ 251.2
General and administrative	$ 62.6	$ 5.3	$ 67.9	$ 51.4	$ 8.5	$ 59.9
Depletion, depreciation, amortization and accretion	$ 359.8	$103.9	$ 463.7	$ 369.6	$112.0	$ 481.6
Current income taxes	$ –	$ 23.0	$ 23.0	$ –	$ 18.2	$ 18.2

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Three Year Summary of Key Measures

Overall, lower production volumes have resulted in lower oil and gas sales and net income during 2007 as compared to 2006. The rise in crude oil prices during 2005, 2006 and 2007 contributed to higher oil and gas sales, however sales moderated in 2007 as a result of lower natural gas prices and production. The following table provides a summary of net income, cash flow and other key measures.

($ millions, except per unit amounts)	2007	2006	2005
Oil and gas sales[(1)]	$1,517.1	$1,572.7	$1,523.7
Net income	339.7	544.8	432.0
Per unit (Basic)[(2)]	2.66	4.48	3.96
Per unit (Diluted)	2.66	4.47	3.95
Cash flow from operating activities	868.5	863.7	774.6
Per unit (Basic)[(2)]	6.80	7.10	7.10
Cash distributions	646.8	614.3	498.2
Per unit (Basic)[(2)]	5.07	5.05	4.57
Payout ratio	74%	71%	64%
Total assets	4,303.1	4,203.8	4,130.6
Long-term debt, net of cash	725.0	679.7	649.8

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average trust units outstanding. Cash distributions to unitholders per unit will not correspond to actual distributions as a result of using the annual weighted average trust units outstanding.

Liquidity and Capital Resources

Sustainability of our Distributions and Asset Base

As an oil and gas producer we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future oil and natural gas production is highly dependent on our success in exploiting our asset base and acquiring or developing additional reserves. To the extent we are unsuccessful in these activities our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions to our unitholders may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

Following the completion of the Focus acquisition, Enerplus has approximately $10 billion of safe harbor growth capacity within the context of the Government's "normal growth" guidelines associated with Bill C-52. This amount is calculated in reference to the combined market capitalizations of Enerplus and Focus on October 31, 2006 and also includes equity that may be issued to replace existing debt of both entities at that time.

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to forecasted cash flows, debt levels and capital spending plans. The level of cash withheld has historically varied between 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, our access to equity markets and funding requirements for our development capital program.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level, determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During 2007 cash distributions of $646.8 million were funded entirely through cash flow of $868.5 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 74% for 2007 compared to 71% in 2006.

Our cash outlays in 2007 were comprised of: $646.8 million of distributions to unitholders, $393.7 million of development capital and office expenditures, and $209.8 million of acquisitions (net of dispositions) for a total of $1,250.3 million. These cash outlays were financed with a combination of: $868.5 million from cash flow from operating activities, $199.6 million from the equity issue, $56.8 million from our distribution reinvestment plan and trust unit rights incentive plan and an increase in our credit facility of $148.8 million.

In aggregate, our 2007 cash distributions of $646.8 million and our development capital and office of $393.7 million totaled $1,040.5 million, or approximately 120% of our cash flow of $868.5 million. We rely on access to capital markets to the extent cash distributions and development capital exceeds cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow, however we would continue to fund acquisitions and growth through additional debt and equity. There will be years when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn and Kirby oil sands projects) where this relationship will vary. Despite our 2007 cash flow being less than the aggregate of our cash distributions and development capital, we continue to have conservative debt levels with a trailing twelve month debt-to-cash flow ratio of 0.8x at December 31, 2007.

For the year ended December 31, 2007 our cash distributions exceeded our net income by $307.1 million (2006 – $69.5 million). Net income includes $520.3 million of non-cash items (2006 – $344.7 million) such as DDA&A, changes in the fair value of our derivative instruments, and future income taxes that do not reduce our cash flow from operations. Future income taxes can fluctuate from period to period as a result of changes in tax rates (such as the enactment of the SIFT tax during the second quarter of 2007), changes in the inter-company royalty, interest and dividends from our operating subsidiaries paid to the Fund. In addition, other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current environment.

The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income.

($ millions, except per unit amounts)	**2007**	2006	2005
Cash flow from operating activities	**$ 868.5**	$863.7	$774.6
Cash Distributions	**646.8**	614.3	498.2
Excess of cash flow over cash distributions	**$ 221.7**	$249.4	$276.4
Net income	**$ 339.7**	$544.8	$432.0
Shortfall of net income over cash distributions	**$(307.1)**	$ (69.5)	$ (66.2)
Cash distributions per weighted average trust unit	**$ 5.07**	$ 5.05	$ 4.57
Payout ratio[(1)]	**74%**	71%	64%

(1) Based on cash distributions divided by cash flow from operating activities.

It is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities in the oil and gas sector due to the nature of reserve reporting, natural reservoir declines and the risks involved with capital investment. Therefore we do not disclose maintenance capital separately from development capital spending.

Asset Retirement Costs

Actual asset retirement costs incurred in the period are deducted for purposes of calculating cash flow. Differences between actual asset retirement costs incurred and the amortization and accretion of the asset retirement obligation are discussed in the Asset Retirement Obligations section of the MD&A and Note 5.

Long-Term Debt

Long-term debt at December 31, 2007 was $726.7 million, an increase of $46.9 million from $679.8 million at December 31, 2006. Long-term debt at December 31, 2007 is comprised of $497.3 million of bank indebtedness, which increased $148.8 million from prior year and $229.3 million of senior unsecured notes. With the adoption of the financial instrument accounting standards (see Note 2) on January 1, 2007 we adjusted the carrying value of our US$175 million senior unsecured notes to fair value of $208.2 million from their previous carrying value of $268.3 million, a decrease of $60.1 million. Subsequent to this adoption entry, our $175 million senior notes have decreased a further $32.2 million as a result of the strengthening Canadian dollar. Increases in long-term debt resulting from the Jonah and Kirby acquisitions along with our development capital program more than offset decreases resulting from the April 2007 equity issue and the foreign exchange impact of the strengthening Canadian dollar on our U.S. dollar denominated senior notes.

In the fourth quarter of 2007 we extended our bank credit facility by one year to November 2010 and increased the facility size to $1.0 billion. Subsequent to December 31, 2007, in conjunction with the Focus acquisition, we increased the bank credit facility size to $1.4 billion. On February 13, 2008 an additional $340 million was drawn on the bank credit facility to settle outstanding indebtedness of Focus.

Our working capital, excluding cash, at December 31, 2007 decreased $73.2 million compared to December 31, 2006. Excluding deferred financial assets and credits, working capital decreased $7.3 million compared to the prior year. This is primarily due to lower accounts receivable in 2007 as a result of lower sales in December 2007 compared to 2006.

We continue to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	Year Ended Dec. 31, 2007	Year Ended Dec. 31, 2006
Long-term debt to trailing cash flow	**0.8 x**	0.8 x
Cash flow to interest expense	**25.8 x**	26.8 x
Long-term debt to long-term debt plus equity	**22%**	20%

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.

Enerplus currently has a $1.4 billion ($1.0 billion at December 31, 2007) unsecured covenant based three-year term bank facility ending November 2010, through its wholly-owned subsidiary EnerMark Inc. We have the ability to extend the facility each year or repay the entire balance at the end of the three-year term. This bank debt carries floating interest rates that we expect to range between 55.0 and 110.0 basis points over Bankers' Acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At December 31, 2007 we are in compliance with our debt covenants, the most restrictive of which limits our long-term debt to three times trailing cash flow reflecting acquisitions

on a pro forma basis. Refer to "Debt of Enerplus" in our Annual Information Form for the year ended December 31, 2006 for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 7.

We anticipate that we will continue to have adequate liquidity to fund planned development capital spending during 2008 through a combination of cash flow retained by the business and debt.

Commitments

Enerplus has contracted to transport 104 MMcf/day of natural gas on the Nova system in the province of Alberta as well as 20 MMcf/day of natural gas on various pipelines to the U.S. midwest. Enerplus also has a contract to transport a minimum of 2,480 bbls/day of crude oil from field locations to suitable marketing sales points within western Canada.

Including Focus, approximately 24% of our current gas production is dedicated to aggregator sales arrangements. Under these arrangements, we receive a price based on the average netback price of the pool, net of transportation costs incurred by the aggregator for the life of the reserves.

In 2007 we extended our Canadian office lease commitments. Our Canadian and U.S. leases now expire in 2014 and 2011, respectively. Annual costs of these lease commitments, include rent and operating fees. The Fund's commitments, contingencies and guarantees are more fully described in Note 13.

As at December 31, 2007 Enerplus has the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					Total
($ millions)	Total	2008	2009	2010	2011	2012	Committed after 2012
Bank credit facility	**$497.3**[(1)]	$ –	$ –	$497.3	$ –	$ –	$ –
Senior unsecured notes	**323.4**[(1)(2)]	–	–	53.7	64.7	64.7	140.3
Pipeline commitments	**31.1**	10.0	5.9	4.0	2.8	2.4	6.0
Office lease	**67.9**	6.9	7.6	10.3	10.8	11.1	21.2
Total commitments[(3)]	**$919.7**	$16.9	$13.5	$565.3	$78.3	$78.2	$167.5

(1) Interest payments have not been included since future debt levels and interest rates are not known at this time.

(2) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap – see Note 12).

(3) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Not reflected in the above schedule are those term contracts for transportation and the office lease that Enerplus assumed upon the completion of the Focus acquisition. The Focus term transportation contracts consist of 45 MMcf/day of natural gas in British Columbia, and 60 MMcf/day of natural gas in Saskatchewan.

Accumulated Deficit

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the period whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, derivative instrument mark-to-market gains and losses, unit based compensation charges, future income tax provisions and non-cash charges resulting from the adoption of the financial instrument accounting standards (see Note 2).

Trust Unit Information

We had 129,813,000 trust units outstanding at December 31, 2007 compared to 123,151,000 trust units at December 31, 2006. The weighted average number of trust units outstanding during 2007 was 127,691,000 (2006 – 121,588,000). At February 20, 2008 we had 160,022,000 trust units outstanding, which reflects the additional trust units issued to acquire Focus, and 9,087,000 exchangeable partnership units outstanding that were assumed with the Focus acquisition and are convertible at the option of the holder into 0.425 of an Enerplus trust unit (3,862,000 trust units).

On April 10, 2007 in conjunction with the acquisition of Kirby we issued 1,105,000 trust units as part of the purchase price consideration representing $54.8 million and also closed a public offering of 4,250,000 trust units for net proceeds of $199.6 million.

In addition 1,307,000 trust units (2006 – 1,242,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights incentive plan, net of redemptions. This resulted in $56.8 million (2006 – $55.9 million) of additional equity to the Fund.

Income Taxes

The following is a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences, as well as consider the Government's proposal to implement a tax on trusts.

Canadian Unitholders

The Fund qualifies as a mutual fund trust under the Income Tax Act (Canada) and accordingly, trust units of the Fund are qualified investments for RRSPs, RRIFs, RESPs, and DPSPs. Each year the Fund has historically transferred all of its taxable income to the unitholders by way of distributions.

In computing income, unitholders are required to include the taxable portion of distributions received in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

We paid $5.04 per trust unit in cash distributions to unitholders on record during 2007. For Canadian tax purposes, approximately 2% of these distributions, or $0.12 per trust unit was a tax deferred return of capital, approximately 98% or $4.92 per trust unit was taxable to unitholders as other income, and there was no eligible dividend income.

For 2008, we estimate that 95% of cash distributions will be taxable and 5% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

U.S. unitholders who received cash distributions were subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable portion of the distribution as computed under Canadian tax law and the non-taxable portion of the distribution. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

For U.S. taxpayers the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. This preferential rate of tax for "Qualified Dividends" is set to expire at the end of 2010. On March 24, 2007, Bill 1672 was introduced into the U.S. House of Representatives which, if enacted as presented, would make dividends from Canadian income funds such as Enerplus ineligible for treatment as a "Qualified Dividend". The dividends would then become a "non-qualified dividend from a foreign corporation" subject to the normal rates of tax commencing with dividends received after the date of enactment. The proposed bill still requires the approval of the House of Representatives, the Senate and the President prior to it being enacted. Therefore, we are unable to determine when or even if the bill will become enacted as presented.

We paid US$4.71 per trust unit to U.S. residents during the 2007 calendar year of which 7% or US$0.33 per trust unit was a tax deferred return of capital and 93% or US$4.38 per unit was a taxable qualified dividend.

For 2008, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

Quarterly Financial Information

In general, oil and gas sales have been decreasing since the first quarter of 2006 due mainly to lower natural gas prices and lower production. Sales increased slightly in the fourth quarter of 2007 due to higher crude oil prices.

Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future tax provisions due to changes in government legislation (SIFT tax and corporate rate reductions) as well as changes to accounting policies adopted during 2007. Furthermore, changes in the fair value of our commodity derivative instruments along with changes in fair value of other financial instruments cause net income to fluctuate between quarters.

Quarterly Financial Information (CDN$ millions, except per trust unit amounts)	Oil and Gas Sales[(1)]	Net Income	Net Income Per Trust Unit	
			Basic	Diluted
2007				
Fourth Quarter	$ 389.8	$ 98.7	$0.76	$0.76
Third Quarter	364.8	93.0	0.72	0.72
Second Quarter	382.5	40.1	0.31	0.31
First Quarter	380.0	107.9	0.88	0.87
Total	$1,517.1	$339.7	$2.66	$2.66
2006				
Fourth Quarter	$ 369.5	$110.2	$0.90	$0.89
Third Quarter	398.0	161.3	1.31	1.31
Second Quarter	403.5	146.0	1.19	1.19
First Quarter	401.7	127.3	1.08	1.07
Total	$1,572.7	$544.8	$4.48	$4.47

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Summary Fourth Quarter Information

In comparing the fourth quarter of 2007 with the same period in 2006:

- Net income decreased 10% to $98.7 million due to increased commodity derivative instrument losses, partially offset by higher oil and gas sales.
- Cash flow was $205.1 million in 2007 similar to $207.1 million in 2006.
- Average daily production decreased 7% to 80,959 BOE/day due to the fire at Giltedge, operational interruptions and reductions in our development capital program.
- The average selling price per BOE increased 13% to $52.33 due to stronger crude oil prices.
- Operating expenses of $8.57/BOE (including non-cash amounts) were similar to the fourth quarter of 2006 at $8.52/BOE.
- G&A expenses including non-cash amounts increased 4% on a BOE basis to $2.21/BOE from $2.13/BOE as a result of lower production.
- Development capital spending decreased 14% compared to the fourth quarter of 2006 as a result of a reduced development capital spending program in 2007.

The following tables provide an analysis of key financial and operating results for the three months ended December 31, 2007 and 2006.

(CDN$ millions, except per unit amounts)	Three Months Ended December 31, 2007	Three Months Ended December 31, 2006
Financial (000's)		
Net Income	$ 98.7	$110.2
Cash Flow from Operating Activities	$205.1	$207.1
Cash Distributions to Unitholders(1)	$163.4	$155.0
Financial per Unit(2)		
Net Income	$ 0.76	$ 0.90
Cash Flow from Operating Activities	$ 1.58	$ 1.69
Cash Distributions to Unitholders(1)	$ 1.26	$ 1.26
Payout Ratio(3)	80%	75%
Average Daily Production	80,959	87,092
Selected Financial Results per BOE(4)		
Oil and Gas Sales(5)	$52.33	$46.11
Royalties	(9.83)	(8.26)
Commodity Derivative Instruments	(0.08)	0.75
Operating Costs	(8.53)	(8.52)
General and Administrative	(1.94)	(1.88)
Interest and Foreign Exchange	(1.70)	(1.02)
Taxes	(1.70)	(0.64)
Restoration and Abandonment	(0.75)	(0.54)
Cash Flow from Operating Activities before changes in non-cash working capital	$27.80	$26.00
Weighted Average Number of Units Outstanding (thousands)	129,658	122,971
Development Capital	106.1	123.1
Net Wells Drilled	76	89
Success Rate	100%	100%
Average Benchmark Pricing		
AECO natural gas – monthly index (CDN$/Mcf)	$ 6.00	$ 6.36
AECO natural gas – daily index (CDN$/Mcf)	$ 6.14	$ 6.91
NYMEX natural gas – monthly NX3 index (US$/Mcf)	$ 7.03	$ 6.62
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	$ 6.89	$ 7.52
WTI crude oil (US$/bbl)	$90.68	$60.21
WTI crude oil: CDN$ equivalent (CDN$/bbl)	$88.90	$68.42
CDN$/US$ exchange rate	1.02	0.88

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit may not correspond to actual distributions of $1.26 per trust unit as a result of using the annual weighted average trust units outstanding.
(2) Based on weighted average trust units outstanding.
(3) Based on cash distributions divided by cash flow from operating activities.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Selected Quarterly Canadian and U.S. Financial Results

(CDN$ millions, except per unit amounts)	Three Months Ended December 31, 2007 Canada	U.S.	Total	Three Months Ended December 31, 2006 Canada	U.S.	Total
Daily Production Volumes						
Natural gas (Mcf/day)	245,219	12,196	257,415	271,061	6,654	277,715
Crude oil (bbls/day)	24,248	9,973	34,221	25,903	10,436	36,339
Natural gas liquids (bbls/day)	3,836	–	3,836	4,467	–	4,467
Total daily sales (BOE/day)	68,953	12,006	80,959	75,547	11,545	87,092
Pricing(1)						
Natural gas (per Mcf)	$ 5.91	$ 5.98	$ 5.91	$ 6.57	$ 6.81	$ 6.58
Crude oil (per bbl)	$ 68.94	$80.16	$ 72.21	$ 52.39	$59.85	$ 54.53
Natural gas liquids (per bbl)	$ 58.12	$ –	$ 58.12	$ 46.15	$ –	$ 46.15
Capital Expenditures						
Development capital and office	$ 94.3	$ 13.7	$ 108.0	$ 96.7	$ 29.1	$ 125.8
Acquisitions of oil and gas properties	$ 5.0	$ 0.1	$ 5.1	$ 4.1	$ 0.7	$ 4.8
Dispositions of oil and gas properties	$ (0.4)	$ (3.6)	$ (4.0)	$ (0.1)	$ –	$ (0.1)
Revenues						
Oil and gas sales(1)	$ 309.5	$ 80.3	$ 389.8	$ 307.9	$ 61.6	$ 369.5
Royalties	$ (56.1)	$ (17.1)(2)	$ (73.2)	$ (54.1)	$ (12.1)(2)	$ (66.2)
Commodity derivative instruments	$ (48.8)	$ –	$ (48.8)	$ (5.4)	$ –	$ (5.4)
Expenses						
Operating	$ 61.0	$ 2.8	$ 63.8	$ 66.4	$ 1.9	$ 68.3
General and administrative	$ 16.5	$ (0.1)	$ 16.4	$ 14.6	$ 2.5	$ 17.1
Depletion, depreciation, amortization and accretion	$ 89.9	$ 21.8	$ 111.7	$ 93.3	$ 26.2	$ 119.5
Current income taxes	$ –	$ 12.6	$ 12.6	$ –	$ 5.1	$ 5.1

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Critical Accounting Policies

The financial statements have been prepared in accordance with GAAP. A summary of significant accounting policies is presented in Note 1. A reconciliation of differences between Canadian and United States GAAP is presented in Note 16. Most accounting policies are mandated under GAAP. However, in accounting for oil and gas activities, we have a choice between two acceptable accounting policies: the full cost and the successful efforts methods of accounting.

The Fund follows the full cost method of accounting for oil and natural gas activities. Using the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to the Fund's net income or net income per unit as the majority of the Fund's drilling activity is not exploration in nature and is more focused on low risk development drilling that has traditionally achieved high success rates.

Under the full cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, on a country by country cost centre basis with the reserves valued using estimated future commodity prices at period end. Under the successful efforts method of accounting, the costs are aggregated on a property-by-property basis. The

carrying value of each property is subject to an impairment test. Each method may generate a different carrying value of property, plant and equipment and a different net income depending on the circumstances at period end. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced and are tested for impairment separately.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and the asset retirement obligation.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with NI 51-101 reserve standards, and (b) future prices of oil and gas.

Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, amounts recorded for depletion, impairment in the cost centre, and the change in fair value of financial contracts.

Trust Unit Rights

Management calculates the fair value of rights granted under our trust unit rights incentive plan using a binomial lattice option-pricing model. This process involves the use of significant estimates and assumptions, which may change over time. The values calculated under the option-pricing model may not reflect the actual value realized by trust unit rights holders.

Derivative Financial Instruments

Management uses derivative financial instruments to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts are subject to fluctuation depending on the underlying estimate of future commodity prices, foreign currency exchange rates and interest rates.

Recent Canadian Accounting and Related Pronouncements

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP, as used by public entities, being converged with International Financial Reporting Standards (IFRS) by 2011. On February 13, 2008 the AcSB confirmed that use of IFRS will be required for public companies beginning January 1, 2011. We continue to assess the impact of adopting IFRS and implementing plans for transition.

Financial Instruments, Comprehensive Income and Hedges

CICA Section 3862 – Financial Instruments – Disclosures

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

This standard is effective for reporting periods beginning January 1, 2008 and will result in additional disclosures for our financial instruments.

CICA Section 3863 – Financial Instruments – Presentation

This standard establishes presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

This standard is effective for reporting periods beginning January 1, 2008 and should have a minimal impact on our reporting.

CICA Section 1535 – Capital Disclosures

This section details disclosures that must be made regarding an entity's capital and how it is managed. The standard requires qualitative information about an entity's objectives, policies and processes for managing capital and quantitative data about what the entity regards as capital. It requires disclosure of compliance with any capital requirements and consequences of any non-compliance.

This standard is effective for reporting periods beginning January 1, 2008 and will result in additional disclosures around managing capital.

Risk Factors and Risk Management

Enerplus investors are participating in the net cash flow from a portfolio of crude oil and natural gas producing properties. As such, the cash distributions and the value of Enerplus units are subject to numerous risk factors. These risk factors, many of which are associated with the oil and gas industry, include, but are not limited to, the following influences:

Canadian Government Tax on Income Trusts

On June 22, 2007, Bill C-52 was passed by the Senate and was given royal assent by the Governor General. As a result, our second quarter future income tax provision includes a future income tax expense of $78.1 million related to this legislation. This non-cash expense relates to temporary differences between the accounting and tax basis of the Fund's assets and liabilities and has no immediate impact on cash flow. Tax pools in 2011 may not be sufficient to shelter taxable income from the new SIFT tax and as a result increased tax may reduce cash flow available for distributions and development spending.

We are currently evaluating alternatives to determine the optimal business structure for our unitholders. However, we currently see value in the three-year tax exemption period through 2010 as a distributing entity and would be hesitant to make major structural changes during this period without compelling reasons that we do not currently foresee.

Commodity Price Risk

Enerplus' operating results and financial condition are dependent on the prices we receive for our crude oil and natural gas production. These prices may fluctuate widely in response to a variety of factors including global and domestic economic conditions, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase, and may be exposed to risk of default by the counterparties. Refer to the price risk management section.

Oil and Gas Reserves and Resources Risk

The value of our trust units are based on, among other things, the underlying value of the oil and gas reserves and resources. Geological and operational risks can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower oil and natural gas prices may increase the risk of write-downs of our oil and gas property investments. Regulatory changes to reporting practices can also result in reserve or resource write-downs.

We strive to acquire low risk, mature properties with a high proportion of proved reserves, positive operating metrics, long reserve lives and predictable production. Similarly, we generally participate in lower-risk development projects while farming out or monetizing higher risk exploratory prospects.

Each year, independent engineers evaluate a significant portion of our proved and probable reserves as well as the resources attributable to our oil sands properties.

Sproule Associates Limited ("Sproule") evaluated 92% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves, in accordance with NI 51-101 and has reviewed the remainder of the reserves Enerplus evaluated internally. GLJ Petroleum Consultants Ltd. ("GLJ") evaluated the Joslyn bitumen reserves as they have previously performed such evaluations for the operator of the Joslyn project. Netherland, Sewell & Associates Inc. ("NSA") of Dallas, Texas, evaluated the reserves attributed to our assets in the United States. Both GLJ and NSA evaluated 100% of the

reserves in their respective areas. Both GLJ and NSA utilized Sproule's forecast and constant price and cost assumptions as of December 31, 2007 in their evaluations to maintain consistency. GLJ also evaluated the resources attributable to our Joslyn and Kirby oil sands projects. The Reserves Committee of the Board of Directors has reviewed and approved the reserve and resource reports of the independent evaluators.

Operational Inflation Risk

Over the last few years we have experienced inflationary pressures on both our development capital costs and our operating costs. Higher costs decrease the amount of cash flow from our operating activities which may affect the amount of distributions to unitholders.

We strive to control costs through incentive-based compensation plans that reward employees for such things as cost control and value-added initiatives. We attempt to minimize costs by exploiting our purchasing strength with suppliers. We use detailed budgeting and accounting practices to monitor costs. Multi-functional teams regularly perform integrated field reviews designed to reduce costs and increase revenues from our properties.

Despite these efforts, it can be difficult to control costs in the oil and gas industry, especially in periods of high commodity prices when the demand for goods and services is strong. Oil and gas production involves a significant amount of fixed costs that are difficult to reduce without decreasing production. In addition, subsequent to the Focus acquisition, approximately 30% of our production is operated by third parties. We have limited ability to influence costs on partner-operated properties.

Access to Transportation Capacity

Market access for crude oil and natural gas production in Canada and the United States is dependent on the ability of Enerplus and the buyers of our production to access sufficient transportation capacity on third party pipelines to transport all production volumes. While the third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity. There are also occasionally operational reasons for curtailing transportation capacity. Accordingly, there can be periods where pipeline capacity is insufficient to transport all of the production from a given region, causing volume curtailments for all shippers, including Enerplus and its production buyers.

We continuously monitor this risk for both the short and longer term through dialogue with the third party pipelines and other market participants, as well as by review of supply and demand studies prepared by third party experts. Where available and commercially appropriate given the production profile and commodity, we attempt to mitigate this risk by contracting for firm transportation capacity or by using other means of transportation.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new reserves and resources and developing existing reserves and resources. Acquisitions of oil and gas assets depend on our assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of our trust units.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions are approved by the Board of Directors and, where appropriate, independent reserve engineer evaluations are obtained.

Non-Resident Ownership and Mutual Fund Trust Status

Since our listing on the New York Stock Exchange in November of 2000, we have seen increased trading volumes and levels of ownership by non-residents of Canada. Based on information received from our transfer agent and financial intermediaries in February 2008, an estimated 72% of our outstanding trust units were held by non-residents. Immediately after the acquisition of Focus, on February 13, 2008, we estimate that approximately 63% of our trust units were held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

Enerplus currently meets the requirements of a Mutual Fund Trust as defined in the Income Tax Act (Canada). Our trust indenture does not have a specific limit on the percentage of trust units that may be owned by non-residents.

At this time, management does not anticipate any legislative changes that would affect our status as a mutual fund trust; however, we have implemented provisions in our trust indenture to allow the Board of Directors to adopt non-resident ownership constraints, if required, in order to ensure Enerplus maintains its mutual fund trust status.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on Enerplus. During 2007 the Alberta government announced proposed changes to the provincial royalty program expected to be effective on January 1, 2009 (see the Royalties section of this MD&A for further details). Canada ratified the Kyoto Protocol in late 2002, which requires countries to reduce their emissions of carbon dioxide and other greenhouse gases. The Canadian federal government is currently gathering information to set emission targets for the industry. The details are projected to be announced by 2010 and could affect capital expenditures and operating costs.

Our operations expose us to possible regulatory changes by both Canadian and U.S. governments. As an oil and gas producer, we are subject to a broad range of regulatory requirements. Similarly, as a mutual fund trust, we have a unique structure that is vulnerable to changes in legislation or income tax law.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas through such activities as participating in industry organizations and conferences, the exchange of information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt and as a result distribute the majority of our cash flow to our unitholders. As such, we are dependent on continued access to the capital markets to fund our activities directed towards maintaining and increasing value for our unitholders. To the extent the cash flow retained by the Fund together with new equity and debt financing is not sufficient to cover required capital expenditures then cash distributions to unitholders may be reduced. Furthermore, current tightening global credit markets may have an adverse effect on our ability to access these capital markets.

Enerplus has listings on the Toronto and New York stock exchanges and maintains an active investor relations program.

We maintain a prudent capital structure by retaining a portion of cash flow for capital spending and utilizing the equity markets when deemed appropriate.

Continued access to capital is dependent on our ability to maintain our track record of performance and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

Health, Safety and Environmental Risk ("HSE")

Health, safety and environmental risks influence the workforce, operating costs and the establishment of regulatory standards.

We have established a HSE Management System designed to:

- *provide staff with the training and resources needed to complete work safely and effectively;*
- *incorporate hazard assessment and risk management as an integral part of everyday business;*
- *monitor performance to ensure that our operations comply with legal obligations and the standards we set for ourselves; and*
- *identify and manage environmental liabilities associated with our existing asset base and potential acquisitions.*

We have a site inspections program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. We carry insurance to cover a portion of our property losses, liability and business interruption. HSE risks are reviewed regularly by the HSE committee comprised of members of the Board of Directors.

Interest Rate Exposure

The Fund has exposure to movements in interest rates. Changing interest rates can affect borrowing costs and the trust unit price of yield-based investments such as Enerplus.

We monitor the interest rate forward market and have fixed the interest rate on approximately 18% of our debt through our senior unsecured notes and interest rate swaps.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as a result of the issuance of senior unsecured notes denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements.

We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are negatively impacted as the Canadian dollar strengthens relative to the U.S. dollar.

We have hedged our foreign currency exposure on both our US$175 million and US$54 million of senior unsecured notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition we have hedged our interest obligation on our US$175 million notes.

We have not entered into any other foreign currency derivatives with respect to oil and gas sales or our U.S. operations.

Counterparty Risk

We assume customer credit risk associated with oil and gas sales, financial hedging transactions and joint venture participants.

We have established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and gas sales, financial hedging transactions and joint venture participants. We maintain a diversified sales customer base and we review our single-entity exposure on a regular basis. We do not have exposure to asset backed commercial paper, however we do have exposure to Canadian and U.S. banks as a counterparty to financial hedging transactions.

Unitholder Liability

In the past, there has been some concern that trust unitholders might be held personally liable for the indebtedness of the Fund.

Enerplus is registered in Alberta, which passed legislation in June 2005 to provide statutory protection for unitholders similar to the protection afforded shareholders in a corporation. Three other provinces (Ontario, Quebec, and Manitoba) also have statutory protection for unitholders. Our bank credit agreement and our debenture agreements do not allow the creditors to extend recourse to unitholders beyond the unitholders' equity investment in the Fund.

Recruitment and Retention of Qualified Personnel

There is strong competition in all aspects of the oil and gas industry. Enerplus competes with a substantial number of other organizations for capital, acquisitions of reserves, undeveloped lands, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in all other aspects of our operations. Other organizations may have greater technical and financial resources than Enerplus which leads to increased competition. Another rising challenge is the recruitment and retention of qualified professional staff at all levels in the organization. Increased activity within the oil and gas sector can create a competitive marketplace which presents challenges in recruiting and retaining key personnel.

In order to attract and retain qualified personnel we offer competitive compensation including performance based plans.

Summary 2008 Outlook

Enerplus offers investors the benefits of owning a large, diversified portfolio of producing oil and natural gas properties within Canada and the United States. As such, our business prospects are closely linked to the opportunities and challenges associated with oil and natural gas production. In particular, we are strongly influenced by the price of crude oil and natural gas, both of which have been volatile in recent years. Our comments with respect to our 2008 outlook should be taken within the context of the current commodity price environment.

The following summarizes Enerplus' 2008 guidance as provided throughout this MD&A and includes the acquisition of Focus at the closing date of February 13, 2008. We do not attempt to forecast commodity prices and, as a result, we do not forecast future cash flow or cash distributions. Readers are encouraged to apply their own price expectations to the following factors to arrive at an expected cash distribution.

Summary of 2008 Expectations	Target	Comments
Average annual production	98,000 BOE/day	Does not include any further potential acquisitions/divestments
Exit rate December 2008 production	100,000 BOE/day	Assumes $580 million development capital spending
2008 production mix	60% gas, 40% liquids	
Average royalty rate	19%	Percentage of gross unhedged sales
Operating costs	$8.65/BOE	
G&A costs	$2.20/BOE	Includes non-cash charges of $0.20/BOE (unit rights incentive plan)
U.S. income and withholding tax – cash costs	20%	Applied to net cash flow generated by U.S. operations and assumes repatriation of the funds to Canada after U.S. development capital spending
Average interest cost	4.5%	Based on current fixed rates and forward market
Payout ratio	60% – 90%	
Development capital spending	$580 million	

We expect our 2008 development capital spending to be $580 million, which is 50% higher than our 2007 spending. We plan to continue to withhold a portion of our cash flow to finance this capital program and we expect the payout ratio to be within our 60-90% guidance range. We believe it is important to maintain a conservative balance sheet as a defense against commodity price changes and to be positioned to capture acquisition opportunities.

We will continue to focus on low-risk development opportunities and review our risk management strategies in response to changing prices and the economics of our acquisition and development projects.

For 2008, we estimate that 95% of cash distributions will be taxable and 5% will be a tax-deferred return of capital for our Canadian unitholders. For our U.S. unitholders, we estimate that 90% of cash distribution will be taxable and 10% will be a tax-deferred return of capital.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting

Under the supervision of our Chief Executive Officer and Chief Financial Officer we have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report and concluded that our disclosure controls and procedures are effective. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Additional Information

Additional information relating to Enerplus Resources Fund, including our Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

Forward-Looking Information and Statements

This management's discussion and analysis ("MD&A") contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratio; future tax treatment of income trusts such as the Fund; future structure of the Fund and its subsidiaries; the Fund's tax pools; the volumes and estimated value of the Fund's oil and gas reserves and resources; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing and in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in this MD&A, our MD&A for the year ended December 31, 2007 and in the Fund's Annual Information Form.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

management's report on internal control over financial reporting

The management of Enerplus Resources Fund is responsible for establishing and maintaining adequate internal control over financial reporting for the Fund. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2007, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Fund's internal control over financial reporting as of December 31, 2007, has been audited by Deloitte & Touche LLP, the Fund's Independent Registered Chartered Accountants, who also audited the Fund's Consolidated Financial Statements for the year ended December 31, 2007.

report of independent registered chartered accountants

To the Board of Directors of Enermark Inc. and Unitholders of Enerplus Resources Fund:

We have audited the internal control over financial reporting of Enerplus Resources Fund and subsidiaries (the "Fund") as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Fund's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Fund's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Fund maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007 of the Fund and our report dated February 27, 2008 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to changes in accounting principles.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2008

management's responsibility for financial statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Resources Fund (the "Fund") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 27, 2008. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte & Touche LLP, Independent Registered Chartered Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Chartered Accountants Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Chartered Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Fund.

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 27, 2008

report of independent registered chartered accountants

To the Board of Directors of Enermark Inc. and Unitholders of Enerplus Resources Fund:

We have audited the accompanying consolidated balance sheets of Enerplus Resources Fund and subsidiaries (the "Fund") as at December 31, 2007 and 2006, and the related consolidated statements of income, accumulated deficit, comprehensive income, accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Resources Fund and subsidiaries as at December 31, 2007 and 2006, and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Fund's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2008 expressed an unqualified opinion on the Fund's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2008

comments by independent registered chartered accountants on canada-united states of america reporting difference

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Fund's financial statements, such as the changes described in Notes 2, 12 and 16 to the consolidated financial statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors of Enermark Inc. and Unitholders of Enerplus Resources Fund, dated February 27, 2008, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2008

consolidated balance sheets

As at December 31 (CDN$ thousands)	2007	2006
Assets		
Current assets		
Cash	$ 1,702	$ 124
Accounts receivable	145,602	175,454
Deferred financial assets (Notes 2 and 3)	10,157	23,612
Future income taxes (Note 11)	10,807	–
Other current	6,373	6,715
	174,641	205,905
Property, plant and equipment (Note 4)	3,872,818	3,726,097
Goodwill (Note 1(f))	195,112	221,578
Other assets (Note 12)	60,559	50,224
	$ 4,303,130	$4,203,804
Liabilities		
Current liabilities		
Accounts payable	$ 269,375	$ 284,286
Distributions payable to unitholders	54,522	51,723
Deferred financial credits (Notes 2 and 3)	52,488	–
	376,385	336,009
Long-term debt (Note 7)	726,677	679,774
Deferred financial credits (Notes 2 and 3)	90,090	–
Future income taxes (Note 11)	304,259	331,340
Asset retirement obligations (Note 5)	165,719	123,619
	1,286,745	1,134,733
Equity		
Unitholders' capital (Note 10)		
Trust Units		
Authorized: Unlimited		
Issued and Outstanding: 2007 – 129,813,445 2006 – 123,150,820	4,032,680	3,713,126
Accumulated deficit	(1,283,953)	(971,085)
Accumulated other comprehensive income (Notes 1(j) and 2)	(108,727)	(8,979)
	(1,392,680)	(980,064)
	2,640,000	2,733,062
	$ 4,303,130	$4,203,804

Signed on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert L. Normand
Director

consolidated statements of accumulated deficit

For the year ended December 31 (CDN$ thousands)	2007	2006
Accumulated income, beginning of year	$ 1,952,960	$ 1,408,178
Adjustment for adoption of financial instruments standards (Note 2)	(5,724)	–
Revised Accumulated income, beginning of year	1,947,236	1,408,178
Net income	339,691	544,782
Accumulated income, end of year	$ 2,286,927	$ 1,952,960
Accumulated cash distributions, beginning of year	$(2,924,045)	$(2,309,705)
Cash distributions	(646,835)	(614,340)
Accumulated cash distributions, end of year	$(3,570,880)	$(2,924,045)
Accumulated deficit, end of year	$(1,283,953)	$ (971,085)

consolidated statements of accumulated other comprehensive income

For the year ended December 31 (CDN$ thousands)	2007	2006
Balance, beginning of year	$ (8,979)	$ (15,568)
Transition adjustments (Note 2):		
Cash flow hedges	660	–
Available for sale marketable securities	14,252	–
Other comprehensive (loss)/income	(114,660)	6,589
Balance, end of year	$ (108,727)	$ (8,979)

consolidated statements of income

For the year ended December 31 (CDN$ thousands except per trust unit amounts)	2007	2006
Revenues		
Oil and gas sales	$1,539,153	$1,595,324
Royalties	(285,148)	(296,554)
Commodity derivative instruments (Notes 3 and 12)	(52,841)	(3,226)
Other income (Note 12)	14,991	2,465
	1,216,155	1,298,009
Expenses		
Operating	274,150	251,239
General and administrative (Note 10(b))	67,921	59,937
Transportation	22,098	22,611
Interest (Note 8)	33,627	32,168
Foreign exchange (Note 9)	(7,071)	(528)
Depletion, depreciation, amortization and accretion	463,718	481,598
	854,443	847,025
Income before taxes	361,712	450,984
Current taxes	23,011	18,236
Future income tax recovery (Note 11)	(990)	(112,034)
Net Income	$ 339,691	$ 544,782
Net income per trust unit		
Basic	$ 2.66	$ 4.48
Diluted	$ 2.66	$ 4.47
Weighted average number of trust units outstanding (thousands)		
Basic	127,691	121,588
Diluted	127,752	121,858

consolidated statements of comprehensive income

For the year ended December 31 (CDN$ thousands)	2007	2006
Net income	$ 339,691	$ 544,782
Other comprehensive (loss)/income, net of tax:		
Unrealized gain on marketable securities	629	–
Realized gains on marketable securities included in net income	(11,302)	–
Gains and losses on derivatives designated as hedges in prior periods included in net income	(733)	–
Change in cumulative translation adjustment	(103,254)	6,589
Other comprehensive (loss)/income	(114,660)	6,589
Comprehensive income (Note 2)	$ 225,031	$ 551,371

consolidated statements of cash flows

For the year ended December 31 (CDN$ thousands)	2007	2006
Operating Activities		
Net income	$ 339,691	$ 544,782
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	463,718	481,598
Change in fair value of derivative instruments (Note 3)	91,852	(31,106)
Unit based compensation (Note 10 (b))	8,435	6,323
Foreign exchange on translation of senior notes (Note 9)	(41,182)	(32)
Future income tax (Note 11)	(990)	(112,034)
Amortization of senior notes premium	(631)	–
Reclassification adjustments from AOCI to net income	(733)	–
Other	(132)	–
Gain on sale of marketable securities (Note 12)	(14,055)	–
Asset retirement obligations settled (Note 5)	(16,280)	(11,514)
	829,693	878,017
Decrease/(Increase) in non-cash operating working capital	38,855	(14,321)
Cash flow from operating activities	868,548	863,696
Financing Activities		
Issue of trust units, net of issue costs (Note 10)	256,369	296,189
Cash distributions to unitholders	(646,835)	(614,340)
Increase in bank credit facilities (Note 7)	148,827	19,888
Decrease in non-cash financing working capital	2,799	2,356
Cash flow from financing activities	(238,840)	(295,907)
Investing Activities		
Capital expenditures	(393,655)	(496,201)
Property acquisitions (Note 6)	(226,480)	(51,313)
Property dispositions	2,947	1,599
Proceeds on sale of marketable securities	16,467	–
Purchase of investments	(2,927)	(29,172)
Increase in non-cash investing working capital	(21,046)	(3,535)
Cash flow from investing activities	(624,694)	(578,622)
Effect of exchange rate changes on cash	(3,436)	864
Change in cash	1,578	(9,969)
Cash, beginning of year	124	10,093
Cash, end of year	$ 1,702	$ 124
Supplementary Cash Flow Information		
Cash income taxes paid	$ 17,431	$ 14,060
Cash interest paid	$ 42,861	$ 34,924

1. Summary of Significant Accounting Policies

The management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the consolidated financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation between Canadian GAAP and United States of America GAAP is disclosed in Note 16. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated. In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc. (the Fund's wholly-owned subsidiary), Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "unitholders") are holders of the trust units issued by the Fund. As a trust under the Income Tax Act (Canada), Enerplus is limited to holding and administering permitted investments and making distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated. Many of the Fund's production activities are conducted through joint ventures and the financial statements reflect only the Fund's proportionate interest in such activities.

(b) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Fund to its customers based on volumes delivered and contractual delivery points and price. A portion of the properties acquired through the March 5, 2003 acquisition of PCC Energy Inc. and PCC Energy Corp. are subject to a royalty arrangement with a private company that is structured as a net profits interest. The results from operations included in the Fund's consolidated financial statements for these properties are reduced for this net profits interest.

(c) Property, Plant and Equipment ("PP&E")

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized on a country by country cost centre basis. Such costs include land acquisition, geological, geophysical, drilling costs for productive and non-productive wells, facilities and directly related overhead charges. Repairs, maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against the capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced.

(d) Impairment Test

A limit is placed on the aggregate carrying value of PP&E (the "impairment test"). The Fund performs an impairment test on a country by country basis. An impairment loss exists when the carrying amount of the country's PP&E exceeds the estimated undiscounted future net cash flows associated with the country's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the country's proved and probable reserves are charged to income. Net costs related to projects in the pre-commercial phase of development are excluded from the country by country impairment test and are tested for impairment separately.

(e) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated on a country by country basis using the unit-of-production method, based on the country's share of estimated proved reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl, reflecting the approximate relative energy content.

(f) Goodwill

The Fund, when appropriate, recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair values of the Canadian and U.S. reporting units are compared to their respective book values. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value of the reporting unit to its identifiable assets and liabilities as if they had been acquired in a business combination for a purchase price equal to their fair value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Changes in goodwill during 2007 represent the effects of foreign exchange recorded in our U.S. subsidiary.

(g) Asset Retirement Obligations

The Fund recognizes as a liability the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Fund estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability. No gains or losses on retirement activities were realized, due to settlements approximating the estimates.

(h) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on Canadian income that is not distributed or distributable to the Fund's unitholders. In the Trust structure, payments made between the Canadian operating entities and the Fund, ultimately transfers both income and future income tax liability to the unitholders. The future income tax liability associated with Canadian assets recorded on the balance sheet is recovered over time through these payments. As the Canadian operating entities transfer all of their Canadian taxable income to the Fund, no provision for current Canadian income tax has been made by any Canadian operating entity.

Effective January 1, 2011, the Fund will be subject to a 28.0% SIFT (specified investment flow-through entities) tax on Canadian income that has not been subject to a Canadian corporate income tax in the Canadian operating entities. Therefore, the future

tax liability associated with Canadian assets recorded on the balance sheet as at that date will be realized over time as the temporary differences between the carrying value of assets in the consolidated financial statements and their respective tax bases are realized. Current Canadian income taxes will be accrued for at that time to the extent that there is taxable income in the Trust or its underlying operating entities.

The U.S. operating entity is subject to U.S. income taxes on its taxable income determined under U.S. income tax rules and regulations. Repatriation of funds from U.S. operations will also be subject to applicable withholding taxes as required under U.S. tax law. A provision has been setup to reflect these current U.S. income taxes.

The Fund follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to the temporary differences between the carrying value of the assets and liabilities on the consolidated financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in these income tax rates on future income tax liabilities and assets is recognized in income during the period that the change occurs.

(i) Financial Instruments

Commencing on January 1, 2007 financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in net income. Financial assets classified as loans and receivables along with financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method. Financial assets classified as available-for-sale are measured at fair value with changes in fair value recognized in other comprehensive income ("OCI"). Investments in equity instruments classified as available-for-sale that do not have a quoted price in an active market or a readily determinable fair value are measured at cost. Transaction costs or fees attributable to the acquisition, issue, or disposal of a financial asset or liability are expensed immediately to net income.

Derivative instruments are recorded on the consolidated balance sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net income.

(j) Foreign Currency Translation

The Fund's U.S. operations are self-sustaining. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment ("CTA") which is part of accumulated other comprehensive income ("AOCI").

Other monetary assets and liabilities, not related to the Fund's U.S. operations, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. The other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expenses are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

(k) Unit Based Compensation

The Fund uses the fair value method of accounting for the trust unit rights incentive plan. Under this method, the fair value of the rights is determined on the date in which fair value can reasonably be determined, generally being the grant date. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

2. Changes in Accounting Policies

Financial Instruments

Effective January 1, 2007, the Fund adopted five new accounting standards that were issued by the CICA: Handbook Section 1530, Comprehensive Income, Handbook Section 3251, Equity, Handbook Section 3855, Financial Instruments – Recognition and Measurement, Handbook Section 3861, Financial Instruments – Disclosure and Presentation and Handbook Section 3865, Hedges. These standards were adopted retrospectively without restatement, with the exception of CTA amounts which have been reclassified to AOCI.

Comprehensive Income

CICA Handbook Section 1530 introduces comprehensive income, which consists of net income and other comprehensive income ("OCI"). Comprehensive income represents changes in equity during a period arising from transactions and other events and circumstances with non-owner sources. OCI comprises revenues, expenses, gains and losses that are recognized in comprehensive income but excluded from net income. Examples of these gains and losses are unrealized gains and losses on marketable securities classified as available-for-sale along with unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations. The Consolidated Statements of Comprehensive Income include a calculation of comprehensive income, while the cumulative changes in OCI are included in the Statements of Accumulated Other Comprehensive Income (AOCI). CICA Handbook Section 3251 establishes standards for the presentation of equity and changes in equity during the period.

Financial Instruments – Recognition and Measurement

CICA Handbook Section 3855 establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments are required to be measured at fair value on recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities.

Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in net income. Financial assets classified as loans and receivables along with financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method. Financial assets classified as available-for-sale are measured at fair value with changes in fair value recognized in OCI. Investments in equity instruments classified as available-for-sale that do not have a quoted price in an active market are measured at cost. Transaction costs or fees attributable to the acquisition, issue, or disposal of a financial asset or liability are expensed immediately to net income.

Derivative instruments are recorded on the consolidated balance sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Embedded derivatives are included as of January 1, 2003. Changes in the fair values of derivative instruments are recognized in net income with the exception of derivatives that are designated as effective cash flow hedges. Refer to the *Hedges* section for further detail.

CICA Handbook Section 3861 establishes standards for the presentation and disclosure of financial instruments and non-financial derivatives.

Hedges

CICA Handbook Section 3865 specifies the criteria and method of accounting for each of the designated hedging strategies.

When hedge accounting is discontinued for a cash flow hedge, the amounts previously recognized in AOCI are reclassified to net income over the remaining term of the hedged item.

When hedge accounting is discontinued for a fair value hedge, the carrying value of the hedged item is no longer adjusted. Any difference between the carrying value and the face value or principal amount of the hedged item is amortized to net income over the remaining term of the original hedging relationship using the effective interest method.

Impact upon Adoption of Sections 1530, 3251, 3855, 3861 and 3865

As a result of the adoption of these standards on January 1, 2007 the Fund elected to stop designating its interest rate and electricity swaps as cash flow hedges and recorded these items on the consolidated balance sheet at their fair values with the offset recorded to opening accumulated other comprehensive income. In addition, the Fund elected to stop designating its cross currency and interest rate swap ("CCIRS") as a fair value hedge and recorded the CCIRS on the consolidated balance sheet at fair value with the offset recorded to opening accumulated deficit. In conjunction, the underlying US$175,000,000 senior unsecured notes were recorded at fair value with the offset recorded to opening accumulated deficit.

The Fund's investments in marketable securities have been classified as available-for-sale and therefore those that have a quoted price in an active market were recorded on the consolidated balance sheet at fair value with the offset recorded to opening AOCI.

Deferred charges of $1,523,000 associated with issuance of the senior unsecured notes were recorded to the opening accumulated deficit.

Amounts previously recorded in the cumulative translation adjustment were reclassified into opening AOCI. Our prior year comparative statements have been restated to reflect this change.

The Fund has recorded the following transition adjustments as of January 1, 2007 in the Consolidated Financial Statements: (a) an increase of $1,494,000 to deferred financial assets to record the electricity swaps at fair value; (b) an increase to other current assets of $14,493,000 to record publicly traded marketable securities at fair value; (c) an increase of $1,708,000 to other assets, consisting of $3,231,000 to record publicly traded marketable securities at fair value less $1,523,000 to write-off the deferred charges associated with the issuance of the senior unsecured notes; (d) an increase of $65,675,000 to deferred financial credits to record the CCIRS and interest rates swaps at fair value; (e) a decrease to long-term debt of $60,111,000 to record the US$175,000,000 senior unsecured note at fair value; (f) an increase to future income taxes of $ 2,943,000 to reflect the tax impact of the adoption entries; (g) an increase of $5,724,000, net of taxes, to the opening accumulated deficit; (h) recognition in AOCI of $14,912,000, net of taxes, related to the net gains on marketable securities classified as available-for-sale along with the fair value of the interest rate and power swaps formerly designated as cash flow hedges. In addition, the Fund reclassified to AOCI $8,979,000 of net unrealized foreign currency losses that were previously presented as a separate item in equity. These transition adjustments are summarized below.

Impact of transition adjustment on selected consolidated balance sheets line items:

Increase/(Decrease) (CDN$ thousands)	**Transition adjustment as at January 1, 2007**
Deferred financial assets	$ 1,494
Other current assets	14,493
Other assets	1,708
Deferred financial credits	65,675
Long-term debt	(60,111)
Future income taxes	2,943
Accumulated deficit	(5,724)
Cumulative translation adjustment	8,979
Accumulated other comprehensive income	5,933

As a result of these changes, net income increased by $5,619,000 ($7,943,000 before future income taxes of $2,324,000) for the year ended December 31, 2007. Both the basic and diluted net income per trust unit calculations for the year ended December 31, 2007 increased by $0.04.

Recent Canadian Accounting Pronouncements

CICA Section 3862 – Financial Instruments – Disclosures

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

This standard is effective for reporting periods beginning after January 1, 2008 and will result in additional disclosures for our financial instruments.

CICA Section 3863 – Financial Instruments – Presentation

This standard establishes presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

This standard is effective for reporting periods beginning after January 1, 2008 and should have a minimal impact on our reporting.

CICA Section 1535 – Capital Disclosures

This section details disclosures that must be made regarding an entity's capital and how it is managed. The standard requires qualitative information about an entity's objectives, policies and processes for managing capital and quantitative data about what the entity regards as capital. It requires disclosure of compliance with any capital requirements and consequences of any non-compliance.

This standard is effective for reporting periods beginning after January 1, 2008 and will result in additional disclosures around managing capital.

3. Deferred Financial Assets and Deferred Financial Credits

The deferred financial assets and credits result from recording our derivative financial instruments at fair value. At December 31, 2007 a current deferred financial asset of $10,157,000, a current deferred financial credit of $52,488,000 and a long-term deferred financial credit of $90,090,000 are recorded on the consolidated balance sheet.

The deferred financial credit relating to crude oil instruments of $52,488,000 at December 31, 2007 consists of the fair value of the financial instruments, representing a loss position of $44,749,000, plus the related deferred premiums of $7,739,000. The

deferred financial asset relating to natural gas instruments of $9,707,000 at December 31, 2007 consists of the fair value of the financial instruments of $10,628,000 less the related deferred premiums of $921,000.

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swaps	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Deferred financial assets/(credits) as at December 31, 2006	$ –	$ –	$ –	$ –	$ 10,922	$12,690	$ 23,612
Adoption of financial instruments standards (Note 2)	(673)	(65,002)	–	1,494	–	–	(64,181)
Change in fair value asset/(credits) (Note 12)	447[(1)]	(24,437)[(2)]	(425)[(3)]	(1,044)[(4)]	(63,410)[(5)]	(2,983)[(5)]	(91,852)
Deferred financial assets/(credits) as at December 31, 2007	$(226)	$(89,439)	$(425)	$ 450	$(52,488)	$ 9,707	$(132,421)
Balance sheet classification:							
Current asset/(credit)	$ –	$ –	$ –	$ 450	$(52,488)	$ 9,707	$ (42,331)
Long-term asset/(credit)	$(226)	$(89,439)	$(425)	$ –	$ –	$ –	$ (90,090)

(1) Recorded in interest expense.
(2) Recorded in foreign exchange expense (loss of $31,777) and interest expense (gain of $7,340).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

The following table summarizes the income statement effects of commodity derivative instruments:

($ thousands)	2007	2006
Change in fair value loss/(gain)	$ 66,393	$(80,980)
Amortization of deferred financial assets	–	49,874
Realized cash (gains)/losses, net	(13,552)	34,332
Commodity derivative instruments loss	$ 52,841	$ 3,226

4. Property, Plant and Equipment

($ thousands)	2007	2006
Property, plant and equipment	$ 6,429,241	$ 5,855,511
Accumulated depletion, depreciation and accretion	(2,556,423)	(2,129,414)
Net property, plant and equipment	$ 3,872,818	$ 3,726,097

Capitalized development general and administrative ("G&A") expenses of $17,185,000 (2006 – $14,111,000) are included in PP&E. The depletion and depreciation calculation includes future capital costs of $521,650,000 (2006 – $472,567,000) as indicated in our reserve reports. Excluded from PP&E for the depletion and depreciation calculation is $321,801,000 (2006 – $81,183,000) related to the Joslyn development project and the Kirby Oil Sands project, both of which have not yet commenced commercial production.

An impairment test calculation was performed on a country by country basis on the PP&E values at December 31, 2007 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Fund's PP&E.

The following table outlines benchmark prices and the exchange rate used in the impairment tests for both Canadian and U.S. cost centres at December 31, 2007:

Year	WTI Crude Oil[(1)] US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude[(1)] CDN$/bbl	Natural Gas 30 day spot @ AECO[(1)] CDN$/Mcf
2008	$89.61	$1.00	$88.17	$6.51
2009	86.01	1.00	84.54	7.22
2010	84.65	1.00	83.16	7.69
2011	82.77	1.00	81.26	7.70
2012	82.26	1.00	80.73	7.61
Thereafter	*	1.00	*	*

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to the Fund.
* Escalation varies after 2012.

5. Asset Retirement Obligations

Total future asset retirement obligations were estimated by management based on the Fund's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Fund has estimated the net present value of its total asset retirement obligations to be $165,719,000 at December 31, 2007 compared to $123,619,000 at December 31, 2006 based on a total undiscounted liability of $542,781,000 and $436,663,000 respectively. These payments are expected to be made over the next 66 years with the majority of costs incurred between 2038 and 2047. To calculate the present value of the asset retirement obligations for 2007 the Fund used a weighted credit-adjusted rate of approximately 6.1% and an inflation rate of 2.0%, (2006 – 6.3% and 2.0%). Settlements during the year approximated our estimates and as a result, no gains or losses were recognized.

Following is a reconciliation of the asset retirement obligations:

($ thousands)	2007	2006
Asset retirement obligations, beginning of year	$123,619	$110,606
Changes in estimates	46,000	12,757
Acquisition and development activity	6,441	5,574
Dispositions	(756)	(45)
Asset retirement obligations settled	(16,280)	(11,514)
Accretion expense	6,695	6,241
Asset retirement obligations, end of year	$165,719	$123,619

6. Property Acquisitions

Kirby Oil Sands Partnership

On April 10, 2007 the Fund acquired a 90% interest in Kirby for total consideration of $182,800,000, consisting of $128,050,000 in cash and the issuance of 1,104,945 trust units at a price of $49.55 per unit ($54,750,000 of equity). On June 22, 2007, the Fund acquired the remaining 10% interest in Kirby for cash consideration of $20,276,000. The acquisition of Kirby has been accounted for as an asset acquisition pursuant to the guidance in the Emerging Issues Committee Abstract 124.

7. Long-term Debt

($ thousands)	2007	2006
Bank credit facilities (a)	$497,347	$348,520
Senior notes (b)		
US$175 million (issued June 19, 2002)	175,973	268,328
US$54 million (issued October 1, 2003)	53,357	62,926
Total long-term debt	$726,677	$679,774

(a) Unsecured Bank Credit Facility

Enerplus currently has a $1.4 billion unsecured covenant based three year term facility ($1.0 billion at December 31, 2007). The facility is extendible each year with a bullet payment required at the end of the three year term. In the first quarter of 2008 the bank credit facility size was increased in conjunction with the acquisition of Focus Energy Trust ("Focus") (see Note 15). At December 31, 2007 Enerplus had available credit of $502,653,000 based on a facility size of $1.0 billion at that time. In conjunction with the Focus acquisition, Enerplus acquired approximately $340 million in Focus debt. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the year ended December 31, 2007 was 5.1% (2006 – 4.8%).

(b) Senior Unsecured Notes

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

On October 1, 2003 when the CDN/US exchange rate was 1.35 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. The notes are translated into Canadian dollars using the period end foreign exchange rate.

During September 2007 Enerplus entered into foreign exchange swaps that effectively fix the five principal payments on the US$54,000,000 senior unsecured notes at a CAD/US exchange rate of 1.02.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, the Fund elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000 (CDN $208,217,000) with the offset to opening accumulated deficit. In addition, the Fund recorded a liability of $65,002,000 with the offset to opening accumulated deficit, which represented the fair value of the CCIRS. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At December 31, 2007 the amortized cost of the US$175,000,000 senior notes was US$178,093,000.

The bank credit facility and the senior notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by its subsidiaries. Payments with respect to the Combined Facilities have priority over payments to the Fund and over claims of and future distributions to the unitholders. However, unitholders have no direct liability beyond their equity investment should cash flow be insufficient to repay the Combined Facilities.

8. Interest Expense

($ thousands)	2007	2006
Realized		
Interest on long-term debt	$41,934	$32,168
Unrealized		
Gain on cross currency interest rate swap	(7,340)	–
Gain on interest rate swaps	(447)	–
Amortization of the premium on senior unsecured notes	(631)	–
Other	111	–
Interest Expense	$33,627	$32,168

9. Foreign Exchange

($ thousands)	2007	2006
Unrealized foreign exchange gain on translation of U.S. dollar denominated senior notes	$(41,182)	$ (32)
Unrealized foreign exchange loss on cross currency interest rate swap	31,777	–
Unrealized foreign exchange loss on foreign exchange swaps	425	–
Realized foreign exchange loss/(gain)	1,909	(496)
Foreign exchange gain	$ (7,071)	$(528)

The US$54,000,000 and US$175,000,000 senior unsecured notes are exposed to foreign currency fluctuations and are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

10. Fund Capital

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

Issued: ($ thousands)	2007 Units	2007 Amount	2006 Units	2006 Amount
Balance before Contributed Surplus, beginning of year	123,151	$3,706,821	117,539	$3,407,567
Issued for cash:				
Pursuant to public offerings	4,250	199,558	4,370	240,287
Pursuant to rights incentive plan	205	6,758	640	22,974
Trust unit rights incentive plan (non-cash) – exercised	–	2,288	–	3,065
DRIP*, net of redemptions	1,102	50,053	602	32,928
Issued for acquisition of corporate and property interests (non-cash)	1,105	54,750	–	–
	129,813	4,020,228	123,151	3,706,821
Contributed Surplus (Trust Unit Rights Incentive Plan)	–	12,452	–	6,305
Balance, end of year	129,813	$4,032,680	123,151	$3,713,126

* Distribution Reinvestment and Unit Purchase Plan

Contributed surplus ($ thousands)	2007	2006
Balance, beginning of year	$ 6,305	$ 3,047
Trust unit rights incentive plan (non-cash) – exercised	(2,288)	(3,065)
Trust unit rights incentive plan (non-cash) – expensed	8,435	6,323
Balance, end of year	$12,452	$ 6,305

On April 10, 2007 the Fund closed an equity offering of 4,250,000 trust units at a price of $49.55 per unit for gross proceeds of $210,588,000 ($199,558,000 net of issuance costs). These trust units were eligible for the April 20, 2007 cash distribution paid to unitholders of record at the close of business on April 10, 2007.

In conjunction with the acquisition of Kirby on April 10, 2007, the Fund issued 1,105,000 trust units at a price of $49.55 per unit for gross proceeds of $54,750,000.

On March 20, 2006 the Fund closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP"), Canadian unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the 20 trading days preceding a distribution payment date without service charges or brokerage fees. Eligible unitholders are also entitled to make optional cash payments to acquire additional trust units; however, the 5% discount does not apply.

Trust units are redeemable by unitholders at approximately 85% of the current market price. Redemptions are limited to $500,000 during any rolling two calendar months. Redemption requests in excess of $500,000 can be paid using investments of the Fund or a non-interest bearing instrument.

(b) Trust Unit Rights Incentive Plan

As at December 31, 2007 a total of 3,404,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Incentive Plan") were outstanding at an average exercise price of $47.59. This represents 2.6% of the total trust units outstanding of which 1,635,000 rights, with an average exercise price of $44.84, were exercisable. Under the Rights Incentive Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the year ended December 31, 2007 reduced the exercise price of the outstanding rights by $2.05 per trust unit of which a $0.52 reduction is effective January 2008 and a $0.51 reduction is effective April 2008. Plan members have the choice to exercise rights using the original exercise price or a reduced strike price. In certain circumstances, it may be more advantageous to use the original exercise price as it could effectively lower the plan member's tax rate on the transaction.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value:

	2007	2006
Dividend yield	10.37%	9.26%
Volatility	26.35%	25.61%
Risk-free interest rate	4.41%	4.13%
Forfeiture rate	6.20%	2.80%
Right's exercise price reduction	$1.75	$1.61

The fair value of the rights granted under the plan during 2007 ranged between 9% and 12% (2006 – 12% and 14% of the underlying market price of a trust unit on the grant date.

During the year the Fund expensed $8,435,000 or $0.07 per unit (2006 – $6,323,000 or $0.05 per unit) of unit based compensation expense using the fair value method. The remaining future fair value of the rights of $6,195,000 at December 31, 2007 (2006 – $10,113,000) will be recognized in earnings over the vesting period of the rights. Activity for the rights issued pursuant to the Rights Incentive Plan is as follows:

	2007		2006	
	Number of Rights (000's)	Weighted Average Exercise Price[(1)]	Number of Rights (000's)	Weighted Average Exercise Price[(1)]
Trust unit rights outstanding				
Beginning of year	3,079	$48.53	2,621	$42.80
Granted	816	48.71	1,473	54.49
Exercised	(205)	32.90	(640)	35.94
Cancelled	(286)	50.74	(375)	46.35
End of year	3,404	$47.59	3,079	$48.53
Rights exercisable at the end of the year	1,635	$44.84	809	$39.81

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The following table summarizes information with respect to outstanding rights as at December 31, 2007. Rights vest between one and three years and expire between four and six years.

Rights Outstanding at December 31, 2007 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable at December 31, 2007 (000's)
16	$26.09	$18.30	2008	16
4	27.70	20.11	2008 - 2009	4
8	33.00	25.72	2008 - 2009	8
7	36.00	29.10	2008 - 2009	7
128	37.62	31.11	2008 - 2009	128
8	40.70	34.58	2008 - 2010	8
23	37.25	31.50	2008 - 2010	23
49	38.83	33.48	2008 - 2010	49
341	40.80	35.80	2008 - 2010	341
68	45.55	40.87	2009 - 2011	45
72	44.86	40.53	2009 - 2011	46
126	49.75	45.82	2009 - 2011	96
532	56.93	53.41	2009 - 2011	364
145	56.55	53.51	2010 - 2012	63
402	54.21	51.67	2010 - 2012	156
252	56.00	53.97	2010 - 2012	114
443	52.90	51.38	2010 - 2012	167
168	48.86	47.84	2011 - 2013	–
444	50.25	49.74	2011 - 2013	–
153	45.14	45.14	2011 - 2013	–
15	38.70	38.70	2011 - 2013	–
3,404	$50.32	$47.59		1,635

(c) Basic and Diluted per Trust Unit Calculations

Net income per trust unit has been determined based on the following:

(thousands)	**2007**	2006
Weighted average units	127,691	121,588
Dilutive impact of rights	61	270
Diluted trust units	127,752	121,858

In 2007 we excluded 222,347 rights because their exercise price was greater than the annual average unit market price of $47.11. No rights were excluded in calculating the weighted average number of diluted units for the year ended December 31, 2006. During the last two years, outstanding rights were the only potential dilutive instrument.

(d) Performance Trust Unit Plan

In 2007 the Board of Directors, upon recommendation of the Compensation Committee, approved new Performance Trust Unit ("PTU") plans for executives and employees. These plans will result in employees and officers receiving cash compensation in

relation to the value of a specified number of underlying notional trust units. The number of notional trust units awarded is variable to individuals and they vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The value determined upon vesting of the PTU Plans is dependent upon the performance of the Fund compared to its peers over the three year period. The level of performance within the peer group then determines a performance multiplier.

At December 31, 2007 there were 179,000 performance trust units outstanding.

11. Income Taxes

The Fund is an inter-vivos trust for income tax purposes. As such, the Fund's income that is not allocated to the Fund's unitholders is taxable. The Fund intends to allocate all income to unitholders.

For 2007, the Fund had taxable income of $632,000,000 (2006 – $588,000,000) or $4.92 per trust unit (2006 – $4.81 per trust unit). Taxable income of the Fund is comprised of dividend, royalty, interest and partnership income, less deductions for Canadian oil and gas property expense ("COGPE") and trust unit issue costs.

There were no dividend income and COGPE deductions for 2007. The amounts of COGPE and issue costs in the fund remaining as at December 31, 2007 are $466,700,000 and $30,289,000 respectively.

Canadian Government's tax on income trusts

On June 22, 2007 Bill C-52, which contained legislative provisions to implement the proposals to tax publicly traded income trusts in Canada became law. As a result, our second quarter future income tax provision included a future income tax expense of $78,110,000 related to this legislation. This non-cash expense related to temporary differences between the accounting and tax basis of the Fund's assets and liabilities at that time and had no immediate impact on cash flow.

On December 14, 2007, Bill C-28, which contained legislative provisions to implement corporate income tax rate reductions announced in the October 30, 2007 fall economic statement, became law. The general corporate tax rate will decrease by 1.0% in 2008 from 20.5% to 19.5%. There are additional rate reductions scheduled until the target federal tax rate of 15.0% is reached as of January 1, 2012. These rate reductions will also apply to the SIFT tax on distributions from income trusts. The SIFT tax rate will fall by 3.5% from 31.5% to 28.0%. As a result, our year to date future income tax provision includes a future income tax recovery of $22,640,000 related to this legislation and other tax rate changes enacted earlier in the year.

We are currently evaluating alternatives to determine the optimal structure for our unitholders. However, we see value in the remaining three-year tax exemption period through 2010 and will look to maintain our current structure during this period unless there are compelling reasons to change.

The future income tax liability on the balance sheet arises as a result of the following temporary differences:

($ thousands)	Canadian	Foreign	2007 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$176,962	$194,393	$371,355
Asset retirement obligations	(41,669)	–	(41,669)
Other	(2,825)	(33,409)	(36,234)
Net future income tax liability/(asset)	$132,468	$160,984	$293,452
Current future income tax asset	$ (10,807)	$ –	$ (10,807)
Long-term future income tax liability	$143,275	$160,984	$304,259

($ thousands)	Canadian	Foreign	2006 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$179,770	$183,081	$362,851
Asset retirement obligations	(37,667)	–	(37,667)
Other	6,963	(807)	6,156
Future income taxes	$149,066	$182,274	$331,340
Current future income tax asset	$ –	$ –	$ –
Long-term future income tax liability	$149,066	$182,274	$331,340

The provision for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2007	2006
Income before taxes	$ 361,712	$ 450,984
Computed income tax expense at the enacted rate of 32.41% (34.88% for 2006)	$ 117,231	$ 157,303
Increase (decrease) resulting from:		
Net income attributed to the Fund	(162,016)	(197,694)
Non-deductible crown royalties	–	11,878
Resource allowance	–	(11,998)
Amended returns and pool balances	5,150	(21,446)
Change in tax rate	(22,640)	(35,500)
SIFT Tax	78,110	–
Other	6,186	3,659
	$ 22,021	$ (93,798)
Future income tax recovery	$ (990)	$(112,034)
Current tax	$ 23,011	$ 18,236

The breakdown of our current and future income tax balances between our Canadian and Foreign operations is as follows:

For the year ended December 31, 2007 ($ thousands)	Canadian	Foreign	Total
Future income (recovery)/expense	$(8,183)	$ 7,193	$ (990)
Current income tax	–	23,011	23,011

For the year ended December 31, 2006 ($ thousands)	Canadian	Foreign	Total
Future income expense	$(113,643)	$ 1,609	$(112,034)
Current income tax	–	18,236	18,236

12. Financial Instruments

(a) Fair Value of Financial Instruments

As a result of the adoption of the new financial instrument and hedging accounting standards described in Note 2, certain financial instruments are now measured and reported on the balance sheet at fair value which were previously reported at amortized cost.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which we have immediate access. Where bid and ask prices are unavailable, we would use the closing price of the most recent transaction for that instrument. In the absence of an active market, we determine fair values based on prevailing market rates for instruments with similar characteristics. Fair values may also be determined based on internal and external valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

The Fund is exposed to the commodity price fluctuations of crude oil and natural gas and to fluctuations in the Canada/US dollar exchange rate. The Fund manages this risk by entering into various derivative financial instruments.

The Fund is exposed to credit risk due to the potential non-performance of counterparties to our financial instruments. The Fund mitigates this risk by having an established credit policy and controls designed to mitigate the risk of default or non-payment.

The Fund has exposure to movements in interest rates. Changing interest rates can affect borrowing costs and the price on yield-based investments such as Enerplus trust units. The Fund monitors the interest rate forward market and has fixed the interest rate on a portion of our debt through our senior unsecured notes and interest rate swaps.

(b) Carrying Value and Fair Value of Financial Instruments

i. Cash

Cash is classified as held-for-trading and is reported at fair value.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables which are reported at amortized cost. At December 31, 2007 the carrying value of accounts receivable approximated their fair value.

iii. Marketable Securities

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. As at December 31, 2007 the Fund reported investments in marketable securities of publicly traded marketable securities at a fair value of $14,676,000. For the year ended December 31, 2007, the change in fair value of these investments represented a gain of $950,000 ($629,000 net of tax).

Marketable securities without a quoted market price in an active market are reported at cost. As at December 31, 2007 the Fund reported investments in marketable securities of private companies at cost of $45,400,000.

During the first quarter of 2007 the Fund disposed of certain marketable securities which resulted in a gain of $14,055,000 ($11,302,000 net of tax) being reclassified from accumulated other comprehensive income to net income. This gain is included in the other income balance of $14,991,000 on the Consolidated Statements of Income.

As at December 31, 2007 total marketable securities of $60,076,000 are included in other assets or other assets on the Consolidated Balance Sheet. Realized gains and losses on marketable securities are included in other income.

iv. Accounts Payable & Distributions Payable to Unitholders

Accounts payable as well as distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At December 31, 2007 the carrying value of these accounts approximated their fair value.

v. Long-term debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at cost. At December 31, 2007 the carrying value of the bank credit facilities approximated their fair value.

US$54 million senior notes

The US$54,000,000 million senior notes, which are classified as other liabilities, are reported at their amortized cost of US$54,000,000 and are translated into Canadian dollars at the period end exchange rate. At December 31, 2007 the Canadian dollar amortized cost of the senior notes was approximately $53,357,000 and the fair value of these notes was $56,585,000.

US$175 million senior notes

The US$175,000,000 million senior notes, which are classified as other liabilities, are reported at amortized cost of US$178,093,000 and are translated to Canadian dollars at the period end exchange rate. At December 31, 2007 the Canadian dollar amortized cost of the senior notes was approximately $175,973,000 and the fair value of these notes was $185,591,000.

vi. Derivative Financial Instruments

Interest Rate Swaps

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 4.10% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps mature between June 2011 and January 2012. The interest rate swaps are classified as held-for-trading and are reported at fair value. At December 31, 2007 the fair value of the interest rate swaps represented a liability of $226,000 and the change in fair value of these contracts represented an unrealized gain of $447,000.

Cross Currency Interest Rate Swap ("CCIRS")

Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. The CCIRS is classified as held-for-trading and is reported at fair value. At December 31, 2007 the fair value of the CCIRS represented a liability of $89,439,000 and the change in fair value of the CCIRS represented an unrealized loss of $24,437,000.

Foreign Exchange Swaps

In September 2007 the Fund entered into foreign exchange swaps on US$54,000,000 of notional debt at an average CAD/US foreign exchange rate of 1.02. These foreign exchange swaps mature between October 2011 and October 2015 in conjunction with the principal repayments on the US$54,000,000 senior notes. The foreign exchange swaps are classified as held-for-trading and are reported at fair value. At December 31, 2007 the fair value of the interest rate swaps represented a liability of $425,000 and the change in fair value of these contracts represented an unrealized loss of $425,000.

Electricity Instruments

The Fund has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2007 the fair value of these contracts represented an asset of $450,000 and the change in fair value of these contracts represented an unrealized loss of $1,044,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at February 20, 2008.

Term	Volumes MWh	Price CDN$/MWh
January 1, 2008 – September 30, 2008	4.0	$63.00
January 1, 2008 – December 31, 2009	4.0	$74.50

The Fund did not enter into any new electricity contracts in the first quarter of 2008.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2007 the fair value of these contracts represented a liability of $52,488,000 and the change in fair value of these contracts represented an unrealized loss of $63,410,000.

The net premium cost of the crude oil instruments entered into as of December 31, 2007 is $7,739,000.

The following table summarizes the Fund's crude oil risk management positions at February 20, 2008:

	Daily Volumes bbls/day	WTI US$/bbl			
		Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
January 1, 2008 – June 30, 2008					
Put	1,500	–	$74.00	–	–
Swap[1]	1,000	–	–	–	$92.61
Swap[1]	500	–	–	–	$94.30
Costless Collar[1][3]	400	$ 79.00	$70.00	–	–
January 1, 2008 – December 31, 2008					
Collar	750	$ 77.00	$67.00	–	–
3-Way option	1,000	$ 84.00	$66.00	$50.00	–
3-Way option	1,000	$ 84.00	$66.00	$52.00	–
3-Way option	1,000	$ 86.00	$68.00	$52.00	–
3-Way option	1,000	$ 87.50	$70.00	$52.00	–
3-Way option	1,500	$ 90.00	$70.00	$60.00	–
Put Spread[1]	1,500	–	$76.50	$58.00	–
Swap	750	–	–	–	$72.94
Swap	750	–	–	–	$74.00
Swap	750	–	–	–	$73.80
Swap	750	–	–	–	$73.35
Swap[1][3]	400	–	–	–	$78.53
April 1, 2008 – December 31, 2008					
Put[2]	700	–	$86.10	–	–
July 1, 2008 – December 31, 2008					
Put Spread[1]	1,500	–	$78.00	$58.00	–
Swap[1]	1,500	–	–	–	$92.00
Swap[1][3]	400	–	–	–	$84.60
January 1, 2009 – December 31, 2009					
Collar[2]	850	$100.00	$85.00	–	–
3-Way option[1]	1,000	$ 85.00	$70.00	$57.50	–
3-Way option[1]	1,000	$ 95.00	$79.00	$62.00	–

(1) Financial contracts entered into during the fourth quarter of 2007.
(2) Financial contracts entered into subsequent to December 31, 2007.
(3) Acquired through the acquisition of Focus.

Natural Gas Instruments

Enerplus has certain financial contracts outstanding as at February 20, 2008 on its natural gas production that are detailed below.

These contracts are classified as held-for-trading and are reported at fair value. At December 31, 2007 the fair value of these contracts represented an asset of $9,707,000 and the change in fair value of these contracts represented an unrealized loss of $2,983,000.

The net premium cost of the financial natural gas instruments entered into as of December 31, 2007 is $921,000.

The following table summarizes the Fund's natural gas risk management positions at February 20, 2008:

Term	Daily Volumes MMcf/day	AECO CDN$/Mcf Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
January 1, 2008 – January 31, 2008					
Call[1]	4.7	$ 9.13	–	–	–
February 1, 2008 – February 29, 2008					
Call[1]	4.7	$ 9.58	–	–	–
January 1, 2008 – March 31, 2008					
Collar	2.4	$ 9.95	$8.00	–	–
Collar	2.4	$10.15	$8.00	–	–
Collar[1][3]	14.2	$ 9.50	$8.70	–	–
3-Way option	4.7	$10.50	$8.20	$5.70	–
3-Way option	9.5	$11.61	$8.97	$6.33	–
3-Way option	4.7	$11.08	$8.55	$6.01	–
3-Way option	4.7	$ 9.50	$7.49	$5.70	–
3-Way option	9.5	$ 9.50	$7.39	$5.70	–
Swap	4.7	–	–	–	$8.70
Swap	2.4	–	–	–	$9.01
Swap[3]	14.2	–	–	–	$8.46
Swap[3]	9.5	–	–	–	$9.07
April 1, 2008 – October 31, 2008					
Collar	6.6	$ 8.44	$7.17	–	–
Collar[1]	6.6	$ 7.49	$6.44	–	–
Collar[1]	5.7	$ 7.39	$6.65	–	–
Collar[2]	11.4	$ 8.65	$7.60	–	–
Collar[2]	2.8	$ 8.65	$7.49	–	–
Collar[2]	2.8	$ 8.86	$7.91	–	–
3-Way option	5.7	$ 9.50	$7.54	$5.28	–
3-Way option[1]	11.8	$ 7.91	$6.75	$5.49	–
3-Way option[1]	11.8	$ 7.91	$6.75	$5.38	–
3-Way option[2]	4.7	$ 8.23	$7.18	$5.28	–
Swap	4.7	–	–	–	$8.18
Swap[1]	7.6	–	–	–	$6.79
Swap[1][3]	14.2	–	–	–	$6.70
Swap[2][3]	14.2	–	–	–	$7.17
Swap[2]	2.8	–	–	–	$7.91
Swap[2]	2.8	–	–	–	$7.87
November 1, 2008 – March 31, 2009					
Collar[2]	5.7	$ 9.50	$8.44	–	–
3-Way option	5.7	$10.71	$7.91	$5.80	–
2007 – 2010					
Physical (escalated pricing)	2.0	–	–	–	$2.59

(1) Financial contracts entered into during the fourth quarter of 2007.
(2) Financial contracts entered into subsequent to December 31, 2007.
(3) Acquired through the acquisition of Focus.

13. Commitments and Contingencies

(a) Pipeline Transportation

Enerplus has contracted to transport 104 MMcf/day of natural gas on the Nova system in the province of Alberta as well as 20 MMcf/day of natural gas on various pipelines to the US midwest. Enerplus also has a contract to transport a minimum of 2,480 bbls/day of crude oil from the field to suitable marketing sales points within western Canada.

(b) Oil Sands Lease #24

The Fund's acquisition of a working interest in the Joslyn project included the assumption of a proportionate share of certain contingent project debt. Effectively, this debt is comprised of principal of $3,150,000 plus accrued interest to December 31, 2007 of $1,571,000. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on attaining certain production hurdles with respect to development of the project. As it is still too early to determine if these hurdles will be satisfied, no portion of the contingent debt has been accrued for in the consolidated financial statements.

(c) Office Lease

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire between 2011 and 2014. Annual costs of these lease commitments include rent and operating fees.

(d) Guarantees

(i) Corporate indemnities have been provided by the Fund to all directors and certain officers of its subsidiaries and affiliates for various items including, but not limited to, all costs to settle suits or actions due to their association with the Fund and its subsidiaries and/or affiliates, subject to certain restrictions. The Fund has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of one of the Fund's subsidiaries and/or affiliates. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) The Fund may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Fund from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

Enerplus has the following minimum annual commitments including long-term debt:

($ thousands)	Total	Minimum Annual Commitment Each Year 2008	2009	2010	2011	2012	Total Committed after 2012
Bank credit facility	$497,347	$ –	$ –	$497,347	$ –	$ –	$ –
Senior unsecured notes	323,408[1]	–	–	53,666	64,682	64,682	140,378
Pipeline commitments	31,063	9,972	5,879	3,960	2,797	2,405	6,050
Office lease	67,875	6,907	7,559	10,304	10,782	11,082	21,241
Total commitments	$919,693	$16,879	$13,438	$565,277	$78,261	$78,169	$167,669

(1) Includes the economic impact of derivative instruments directly related to the senior unsecured notes (CCIRS and foreign exchange swap – see Note 12).

In addition, the Fund is involved in claims and litigation arising in the normal course of business. The resolution of these claims is uncertain and there can be no assurance they will be resolved in favour of the Fund; however, management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

Not reflected in the above schedule are those term contracts for transportation and the office lease that Enerplus assumed upon the completion of the Focus acquisition. The Focus term transportation contracts consist of 45 MMcf/day of natural gas in British Columbia, and 60 MMcf/day of natural gas in Saskatchewan.

14. Geographical Information

As at December 31, 2007 ($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$1,252,413	$286,740	$1,539,153
Capital assets	3,293,413	579,405	3,872,818
Goodwill	47,532	147,580	195,112

As at December 31, 2006 ($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$1,323,631	$271,693	$1,595,324
Capital assets	3,101,277	624,820	3,726,097
Goodwill	47,532	174,046	221,578

15. Events Subsequent to December 31, 2007

On February 13, 2008, Enerplus closed the acquisition of Focus. Under the plan of arrangement, Focus unitholders received 0.425 of an Enerplus trust unit for each Focus trust unit. This transaction is being accounted for as a business combination and the purchase price equation has not yet been determined. Total estimated consideration, including deal costs and assumed debt, is $1.7 billion, consisting of trust units issued and trust units issuable in respect of convertible limited partnership units.

Enerplus issued a total of 30,150,000 trust units and assumed 9,087,000 Class B units of Focus Limited Partnership, each exchangeable, at the option of the holder for no additional consideration, into 0.425 of an Enerplus trust unit.

16. Differences Between Canadian and United States Generally Accepted Accounting Principles

The Fund's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Fund's consolidated statements differ from United States GAAP ("U.S. GAAP") as follows:

The application of U.S. GAAP would have the following effects on net income as reported:

($ thousands)	2007	2006
Net income as reported in the Consolidated Statement of Income – Canadian GAAP	$ 339,691	$ 544,782
Adjustments:		
Depletion, depreciation, amortization and accretion (Note (a))	60,749	74,391
Unrealized gain on cross-currency and interest rate swap (Note (b))	–	1,245
Capitalized interest (Note (c))	5,039	3,436
Compensation expense (Note (d))	14,944	(2,237)
Income tax expense of DDA&A and capitalized interest adjustments	(12,249)	(23,218)
Income tax expense due to changes in tax rates	(66,761)	(35,016)
Net income – U.S. GAAP	$ 341,413	$ 563,383
Other comprehensive (loss)/income as reported in the Consolidated Statement of Comprehensive Income – Canadian GAAP	$ (114,660)	$ 6,589
Adjustments:		
Change in fair value of cash flow hedges (2006 – $49,882 net of tax of $14,595) (Note (b))	–	35,287
Change in fair value of available for sale securities (2006 – $6,827 net of tax of $1,998) (Note (e))	–	4,829
Other comprehensive (loss)/income – U.S. GAAP	$ (114,660)	$ 46,705
Comprehensive income – U.S. GAAP	$ 226,753	$ 610,088
Net income per trust unit		
Basic	$ 2.67	$ 4.63
Diluted	$ 2.67	$ 4.62
Weighted average number of trust units outstanding		
Basic	127,691	121,588
Diluted	127,846	121,860
Deficit:		
Balance, beginning of year – U.S. GAAP	$(3,015,590)	$(3,551,509)
Net income – U.S. GAAP	341,413	563,383
Change in redemption value (Note (f))	1,218,915	586,876
Cash distributions	(646,835)	(614,340)
Balance, end of year – U.S. GAAP	$(2,102,097)	$(3,015,590)
Accumulated other comprehensive income/(loss):		
Balance, beginning of year – U.S. GAAP	$ 5,933	$ (40,772)
Other comprehensive (loss)/income	(114,660)	46,705
Balance, end of year – U.S. GAAP	$ (108,727)	$ 5,933

Reconciliation of Accumulated Other Comprehensive (loss)/income:

As at December 31 ($ thousands)	2007	2006
Unamortized portion of former cash flow hedges, loss of $92, net of tax of $19 (2006 – gain of $821, net of tax of $161)	$ (73)	$ 660
Unrealized gain on available for sale securities, $4,618 net of tax of $1,039 (2006 – $17,724 net of tax of $3,472)	3,579	14,252
Cumulative translation adjustment	(112,233)	(8,979)
Accumulated other comprehensive (loss)/income	$(108,727)	$ 5,933

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($ thousands)	Canadian GAAP	Increase/ (Decrease)	U.S. GAAP
December 31, 2007			
Assets:			
Property, plant and equipment, net (Notes (a)(c))	$ 3,872,818	$ (568,765)	$ 3,304,053
Liabilities:			
Trust unit rights liability (Note (d))	$ –	$ 4,764	$ 4,764
Future income taxes/Deferred income taxes	304,259	(122,002)	182,257
Unitholders' mezzanine equity (Note (f))	–	4,399,297	4,399,297
Unitholder's Equity:			
Unitholders' capital (Note (f))	$ 4,020,228	$(4,020,228)	$ –
Contributed surplus (Note (d))	12,452	(12,452)	–
Deficit (Note (f))	(1,283,953)	(818,144)	(2,102,097)
December 31, 2006			
Assets:			
Other current assets (Note (e))	$ 6,715	$ 14,493	$ 21,208
Property, plant and equipment, net (Notes (a)(c))	3,726,097	(634,553)	3,091,544
Other assets (Note (e))	50,224	3,231	53,455
Liabilities:			
Deferred credits/Financial derivative liabilities (Note (b))	$ –	$ 64,181	$ 64,181
Trust unit rights liability (Note (d))	–	14,298	14,298
Long-term debt (Note (b))	679,774	(60,111)	619,663
Future income taxes/Deferred income taxes	331,340	(197,576)	133,764
Unitholders' mezzanine equity (Note (f))	–	5,305,098	5,305,098
Unitholder's Equity:			
Unitholders' capital (Note (f))	$ 3,706,821	$(3,706,821)	$ –
Contributed surplus (Note (d))	6,305	(6,305)	–
Deficit (Note (f))	(971,085)	(2,044,505)	(3,015,590)
Accumulated other comprehensive income/(loss) (Notes (b)(e)(g))	(8,979)	14,912	5,933

(a) Property, Plant and Equipment and Depletion, Depreciation, Amortization and Accretion

Under U.S. GAAP full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proved reserves, discounted at 10% (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproved properties. Under Canadian GAAP, an impairment loss exists when the carrying amount of the Fund's PP&E exceeds the estimated undiscounted future net cash flows associated with the Fund's proved reserves. If an impairment loss is determined to exist, the costs carried

on the balance sheet in excess of the discounted future net cash flows associated with the Fund's proved and probable reserves are charged to income. The application of the impairment tests under Canadian and U.S. GAAP did not result in a write-down of capitalized costs in either 2007 or 2006.

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for DDA&A will differ in subsequent years. Historically the Fund's U.S. GAAP ceiling test write-downs have exceeded the Canadian GAAP write-downs. As a result, U.S. GAAP DDA&A charges are lower than Canadian GAAP DDA&A charges.

A U.S. GAAP difference also exists relating to the basis of measurement of proved reserves that is utilized in the depletion calculation. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using future prices and costs.

For the year ended December 31, 2007 DDA&A calculated under U.S. GAAP was $60,749,000 ($49,438,000 net of tax) lower than DDA&A calculated under Canadian GAAP. For the year ended December 31, 2006 DDA&A calculated under U.S. GAAP was $74,391,000 ($52,542,000 net of tax) lower than DDA&A calculated under Canadian GAAP.

(b) Derivative Instruments and Hedging

Effective January 1, 2007, the Fund adopted three new Canadian accounting standards issued by the CICA: Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments – Recognition and Measurement, and Handbook Section 3865, Hedges. With the adoption of these standards these U.S. GAAP differences no longer exist.

Under Canadian GAAP prior to January 1, 2007, disclosure of the fair value of derivative financial instruments that qualified for hedge accounting was required with no effect on assets, liabilities or net income. Under U.S. GAAP, all derivative instruments are recognized on the balance sheet as either an asset or liability measured at fair value. Changes in the fair value are recognized in earnings unless specific hedge criteria are met.

Fair Value Hedges

Prior to January 1, 2007 a U.S. GAAP difference existed as the Fund's cross-currency interest rate swap ("CCIRS") was designated as a fair value hedge. For derivative instruments designated as fair value hedges, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value under U.S. GAAP. The change in fair value of both items is reflected in earnings.

Cash Flow Hedges

Prior to January 1, 2007 a U.S. GAAP difference existed as the Fund's interest rate and electricity swaps were designated as cash flow hedges. Under U.S. GAAP changes in the fair value of derivatives that are designated as cash flow hedges are recognized in earnings in the same period as the hedged item. The effective portion of the change in fair value is recognized in other comprehensive income with any ineffectiveness recognized in net income.

Effective December 31, 2005 the Fund stopped designating commodity financial contracts as cash flow hedges in accordance with CICA AcG-13, "Hedging Relationships". As a result of this change, a deferred credit and deferred financial asset of $49,874,000 were recognized representing the fair value of these financial contracts. The deferred asset was amortized to income during 2006 over the remaining term of the contracts. Under U.S. GAAP, the fair value these contracts was recorded on the balance sheet at fair value with the offset recorded in accumulated other comprehensive income as at December 31, 2005. The amount recognized in accumulated other comprehensive income will be reclassified to earnings in the same period as the

corresponding gains or losses associated with the hedged item. In 2006, $49,874,000 was reclassified from accumulated other comprehensive income to earnings.

(c) Interest Capitalization

U.S. GAAP requires interest expense to be capitalized for development projects that have not reached commercial production. A U.S. GAAP difference exists as there is not a similar requirement under Canadian GAAP. For the year ended December 31, 2007 the Fund capitalized interest of $5,039,000 ($4,101,000 net of tax) (2006 – $3,436,000, $2,431,000 net of tax) related to projects under development.

(d) Unit-based Compensation

A U.S. GAAP difference exists as rights granted under our rights plan are considered liability awards for U.S. GAAP and equity awards under Canadian GAAP. The distinction between a liability award and an equity award has an impact on the related accounting treatment.

Under Canadian GAAP rights are accounted for using the fair value method for an equity award. Under this method, the fair value of the right is determined using a binomial lattice option–pricing model on the grant date and is not subsequently remeasured. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the fair value recorded in contributed surplus is recorded to unitholders' capital.

Under U.S. GAAP rights are accounted for using the fair value method for a liability award. Under this method, the trust unit rights liability is calculated based on the rights fair value determined using a binomial lattice option-pricing model at each reporting date until the date of settlement. Compensation cost for each period is based on the change in the fair value of the rights for each reporting period. When rights are exercised, the proceeds, together with the amount recorded as a trust unit rights liability, are recorded to mezzanine equity.

The following assumptions were used to arrive at the estimate of fair value as at December 31 for each the respective years:

	2007	2006
Dividend yield	**13.02%**	9.53%
Volatility	**26.47%**	27.88%
Risk-free interest rate	**3.96%**	3.94%
Forfeiture rate	**6.20%**	2.80%
Right's exercise price reduction	**$1.84**	$1.67

The weighted average grant date fair value of trust unit rights granted in 2007 was $5.54 per trust unit right (2006 – $6.83). The total intrinsic value of trust unit rights exercised during 2007 was $3,025,000 (2006 – $14,900,000).

As at December 31, 2007 1,635,000 trust unit rights were exercisable at a weighted average reduced exercise price of $44.84 with a weighted average remaining contractual term of 3.8 years, giving an aggregate intrinsic value of $3,670,000. As at December 31,. 2006, 809,000 trust unit rights were exercisable at a weighted average reduced exercise price of $39.81 with a weighted average remaining contractual term of 3.9 years, giving an aggregate intrinsic value of $9,700,000.

The following chart details the U.S. GAAP differences related to our trust unit rights plan for the years ended December 31, 2007 and 2006.

	2007			2006		
	CDN GAAP	U.S. GAAP	Difference	CDN GAAP	U.S. GAAP	Difference
Compensation expense	$ 8,435,000	$(6,509,000)	$(14,944,000)	$6,323,000	$ 8,560,000	$ 2,237,000
Contributed Surplus	$12,452,000	$ –	$(12,452,000)	$6,305,000	$ –	$ (6,305,000)
Trust unit rights liability	$ –	$ 4,764,000	$ 4,764,000	$ –	$14,298,000	$14,298,000

(e) Marketable Securities

Prior to January 1, 2007, under Canadian GAAP, the Fund accounted for its marketable securities using the cost method and only disclosed the fair value. Under U.S. GAAP marketable securities that have a readily determinable fair value are considered available for sale and are recorded on the balance sheet at fair value with changes in fair value recognized in comprehensive income.

With the adoption of the new Canadian accounting standards on January 1, 2007 this U.S. GAAP difference no longer exists.

As at December 31, 2006 available for sale marketable securities included in other current assets had a fair value of $16,758,000 and an amortized cost of $2,265,000, resulting in a gross unrealized holding gain of $14,493,000. Available for sale marketable securities included in other assets had a fair value of $13,231,000 and an amortized cost of $10,000,000, resulting in a gross unrealized holding gain of $3,231,000.

For the year ended December 31, 2006, the unrealized holding gain on available for sale securities included in accumulated other comprehensive income increased by $6,827,000.

For the year ended December 31, 2006, the Fund disposed of available for sale marketable securities for proceeds of $5,154,000 resulting in a gain of $1,425,000 being included in net income. The Fund uses the average cost method in computing realized gains or losses on sales of marketable securities.

For the year ended December 31, 2006, the Fund had marketable securities totaling $38,700,000 that were carried at cost.

(f) Unitholders' Mezzanine Equity

A U.S. GAAP difference exists as a result of the redemption feature in the Fund's trust units, which is required for the Fund to retain its Canadian mutual fund trust status. The trust units are redeemable at the option of the holder for approximately 85% of the current trading price. The amount of trust units that are redeemable for cash is limited to $500,000 in any two consecutive months. Any redemption in excess of the limit may be honored with promissory notes or other investments of the Fund. For Canadian GAAP, the trust units are considered to be permanent equity and are presented as unitholders' capital. Under U.S. GAAP, the redemption feature of the trust units excludes them from classification as permanent equity and results in the trust units being classified as mezzanine equity.

For U.S. GAAP the Fund has recorded unitholders' mezzanine equity in the amount of $4,399,297,000 for 2007 (2006 – $5,305,098,000), which represents the estimated redemption value of the trust units at 85% of the year-end market price. In addition, the Fund has recognized a deficit of $2,102,097,000 for 2007 (2006 – $3,015,590,000) resulting from eliminating unitholders' capital and replacing it with unitholders' mezzanine equity at redemption value. Changes in unitholders' mezzanine equity in excess of trust units issued, net of redemptions, net income and cash distributions in any period are recognized as charges to the deficit.

(g) Cumulative Translation Adjustment

Prior to January 1, 2007 a U.S. GAAP difference existed relating to the cumulative translation adjustment that is generated upon translating the financial statements of the Fund's U.S. subsidiaries. Previously under Canadian GAAP the cumulative translation adjustment was deferred and included as a separate component of equity. For U.S. GAAP this amount is recognized in comprehensive income. With the adoption of the new Canadian standards on January 1, 2007 Canadian GAAP is substantially harmonized with U.S. GAAP and this U.S. GAAP difference no longer exists. Prior period amounts have been restated.

(h) FASB Interpretation No. 48 – Accounting for Uncertainty in Income Taxes Disclosures

In June 2006 the FASB issued FASB Interpretation No. 48 – Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109. This guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. The Fund adopted this standard on January 1, 2007.

As a multinational entity, we are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations.

An unrecognized tax benefit is defined as the difference between tax positions taken in a tax return and amounts recognized in the financial statements. Prior to 2007, the tax benefits associated with tax uncertainties, if any, were recognized to the extent it was more likely than not that they would be realized. The implementation of FIN 48 did not impact these amounts.

Pursuant to FIN 48, each year we review the balance of estimated tax liabilities and we determine whether the recognition and measurement criteria of FIN 48 have changed. Where the criteria are no longer met, we reverse the liability and recognize a tax recovery during that period. In addition, where the filing positions taken in the current year do not meet the measurement criteria, we will record a liability and recognize a tax expense.

In accordance with our accounting policy, we recognize potential accrued interest and penalties related to unrecognized tax benefits as a component of Interest expense on the Consolidated Statements of Income.

The following table summarizes the activity related to our unrecognized tax benefits for 2007:

($ thousands)	2007
Balance, beginning of year	$1,500
Accrued interest	100
Balance, end of year	$1,600

Of the balance of unrecognized tax benefits as at December 31, 2007 $950,000, if recognized, would affect the effective tax rate. We expect that the unrecognized tax benefits will decrease by $800,000 in the next twelve months due to lapse of applicable statute of limitations.

In most cases any uncertain tax positions are related to taxation years that remain subject to examination by the relevant taxable authorities. The open taxation years for which no examination has been initiated or the examination is in progress is 2001 onward for Canada and 2004 onward for the United States.

(i) Additional Disclosures Required under U.S. GAAP

i. The components of accounts receivable are as follows:

As at December 31 ($ thousands)	2007	2006
Oil & Gas Sales and Accruals	$ 96,150	$111,049
Joint Venture	49,879	62,311
Other	1,562	3,552
Less: Allowance for Doubtful Accounts	(1,989)	(1,458)
	$145,602	$175,454

ii. The components of accounts payable are as follows:

As at December 31 ($ thousands)	2007	2006
Contractors and Vendors	$118,203	$137,539
Accrued Liabilities	151,172	146,747
	$269,375	$284,286

iii. Net Oil and Gas Sales

Under U.S. GAAP oil and gas sales are presented net of royalties.

For the year ended December 31 ($ thousands)	2007	2006
Oil and Gas Sales	$1,539,153	$1,595,324
Royalties	(285,148)	(296,554)
Net Oil and Gas Sales	$1,254,005	$1,298,770

iv. Consolidated Cash Flows:

The consolidated statements of cash flows prepared in accordance with Canadian GAAP present operating cash flow before changes in non-cash working capital items. This sub-total cannot be presented under U.S. GAAP.

The following chart details the changes in non-cash working capital:

($ thousands)	2007	2006
Accounts Receivable	$ 29,852	$ (4,831)
Other current	342	20,036
Accounts Payable	(14,911)	(32,589)
Distributions Payable to Unitholders	2,799	2,356
Other	2,526	(472)
Total Change in non-cash working capital	$ 20,608	$(15,500)
Relating to:		
Operating Activities	$ 38,855	$(14,321)
Financing Activities	2,799	2,356
Investing Activities	(21,046)	(3,535)
	$ 20,608	$(15,500)

U.S. Pronouncements

The following new accounting pronouncements have been issued, but have not yet been adopted as of December 31, 2007:

In September 2006 the Financial Accounting Standards Board ("FASB") issued SFAS 157 – Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. However, in some cases, the application of SFAS No. 157 may change current practice for measuring and disclosing fair values under other accounting pronouncements that require or permit fair value measurements. For the Fund, SFAS No. 157 is effective as of January 1, 2008 and must be applied prospectively except in certain cases. The adoption of SFAS No. 157 is not expected to materially affect the Funds consolidated results of operations or financial position.

In February 2007 the FASB issued SFAS 159 – The Fair Value Option for Financial Assets and Financial Liabilities. This Statement permits entities to choose to measure certain financial instruments at fair value. For the Fund, SFAS No. 159 is effective as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. The Fund has determined it will not elect fair value measurements for financial assets and financial liabilities included in the scope of SFAS No. 159.

In November 2007 the FASB issued Statement 141(R) – Business Combinations. SFAS No. 141(R) requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and cannot be early adopted.

5 year detailed statistical review

($ thousands, except per unit amounts)	2007	2006	2005	2004	2003
Financial					
Oil and gas sales[1]	$1,464,214	$1,569,487	$1,413,734	$ 989,266	$ 890,011
Cash flow from operating activities	868,548	863,696	774,633	555,060	427,434
Cash distributions to unitholders	646,835	614,340	498,205	423,311	372,576
Per unit	5.04	5.04	4.47	4.20	4.29
Cash withheld for acquisitions and capital expenditures	221,713	249,356	276,428	113,248	34,145
Development capital spending	387,165	491,226	368,689	206,874	157,706
Acquisitions	274,244	51,313	704,028	636,326	225,293
Divestments	9,572	21,127	66,511	31,742	73,214
Total net capital expenditures	658,327	526,387	1,010,549	813,636	312,073
Total assets	4,303,130	4,203,804	4,130,623	3,180,748	2,661,765
Long-term debt, net of cash	724,975	679,650	649,825	584,991	257,701
Payout ratio[2]	74%	71%	64%	76%	87%
Net debt/cash flow ratio	0.8x	0.8x	0.8x	1.1x	0.6x
Trust Unit Trading Information					
Toronto Stock Exchange trading summary					
Close	$ 39.87	$ 50.68	$ 55.86	$ 43.60	$ 39.35
Volume	96,898	82,120	62,278	52,821	51,800
New York Stock Exchange trading summary					
Close	$ 40.05	$ 43.61	$ 47.98	$ 36.31	$ 30.44
Volume	54,192	81,677	70,454	67,570	60,624
Weighted average number of units outstanding (basic)	127,691	121,588	109,083	99,273	86,202
Number of units outstanding at December 31	129,813	123,151	117,539	104,124	94,349
Average Benchmark Pricing					
AECO natural gas (per Mcf)	$ 6.61	$ 6.99	$ 8.48	$ 6.79	$ 6.70
NYMEX natural gas (US$ per Mcf)	6.92	7.26	8.55	6.09	5.54
WTI crude oil (US$ per bbl)	72.34	66.22	56.56	41.40	31.04
CDN$/US$ exchange rate	0.93	0.88	0.83	0.77	0.72

($ per BOE except percentage data)	2007	2006	2005	2004	2003
Oil and Gas Economics					
Net royalty rate	19%	19%	19%	21%	20%
Weighted average price[3]	$ 50.48	$ 50.23	$ 52.36	$ 40.90	$ 36.94
Hedging[4]	0.45	(1.10)	(4.90)	(3.50)	(1.81)
Weighted average price[1]	50.93	49.13	47.46	37.40	35.13
Net royalty expense	9.49	9.36	10.21	8.40	7.51
Operating expense[4]	9.11	8.02	7.45	7.14	6.73
Operating netback	32.33	31.75	29.80	21.86	20.89
General and administrative expense[4]	1.98	1.71	1.28	1.06	0.95
Management fee	–	–	–	–	2.29
Interest expense, net of interest and other income[4]	1.37	0.95	0.51	0.68	0.74
Foreign exchange[4]	0.06	(0.02)	0.13	(0.01)	0.08
Taxes	0.77	0.70	0.31	0.24	0.26
Restoration and abandonment cash costs	0.54	0.37	0.27	0.25	0.26
Cash flow before changes in non-cash working capital	$ 27.61	$ 28.04	$ 27.30	$ 19.64	$ 16.31

(1) Net of commodity derivative instruments and transportation.
(2) Calculated as cash distributions to unitholders divided by cash flow from operating activities.
(3) Net of transportation and before the effects of commodity derivative instruments.
(4) Does not include non-cash portion of expense.

operational statistics

The following information outlines Enerplus' gross average daily production volumes for the years indicated and our company interest reserves based upon forecast prices and costs at December 31 each year.

	2007[1]	2006[1]	2005[1]	2004[1]	2003[1]
Daily Production					
Oil Sands (bbls/day)	n/a	n/a	n/a	n/a	n/a
Crude Oil (bbls/day)	34,506	36,134	29,315	25,550	24,597
NGLs (bbls/day)	4,104	4,483	4,689	4,398	4,666
Natural Gas (Mcf/day)	262,254	270,972	274,336	271,091	240,907
BOE per day	82,319	85,779	79,727	75,130	69,414
Drilling Activity (net wells)	252	361	393	367	294
Success Rate	99%	99%	99%	99%	99%
Production Replacement	90%	82%	247%	384%	91%
Proved Reserves[2]					
Oil Sands (Mbbls)	8,568	8,730	9,453	n/a	n/a
Crude Oil (Mbbls)	125,238	125,048	129,745	104,408	91,063
NGLs (Mbbls)	11,785	12,690	13,084	12,776	13,571
Natural Gas (MMcf)	866,077	920,061	965,776	971,598	867,204
MBOE	289,937	299,812	313,245	279,117	249,168
Probable Reserves[2]					
Oil Sands (Mbbls)	54,930	47,998	43,700	47,747	n/a
Crude Oil (Mbbls)	35,504	34,421	31,567	26,783	27,807
NGLs (Mbbls)	3,827	3,777	3,539	3,292	3,742
Natural Gas (MMcf)	336,214	344,025	342,518	295,698	284,096
MBOE	150,297	143,533	135,892	127,105	78,898
Proved Plus Probable Reserves[2]					
Oil Sands (Mbbls)	63,498	56,728	53,153	47,747	n/a
Crude Oil (Mbbls)	160,742	159,469	161,312	131,191	118,870
NGLs (Mbbls)	15,612	16,467	16,623	16,068	17,313
Natural Gas (MMcf)	1,202,291	1,264,086	1,308,294	1,267,296	1,151,300
MBOE	440,234	443,345	449,137	406,222	328,066
Reserve Life Index[3]					
Without Oil Sands:					
Proved (years)	10.0	9.8	9.6	10.1	10.6
Proved Plus Probable (years)	12.8	12.2	12.0	12.4	13.3
With Oil Sands:					
Proved (years)	10.3	10.1	9.9	10.1	10.6
Proved Plus Probable (years)	14.8	14.0	13.5	14.0	13.3

(1) 2003 - 2007 reserve information reflects NI 51-101 reporting methodology.

(2) Company interest reserves consist of gross reserves (as defined in National Instrument 51-101) plus Enerplus' royalty interests. Company interest reserves are not a term defined in National instrument 51-101 and may not be comparable to reserves disclosed by other issuers.

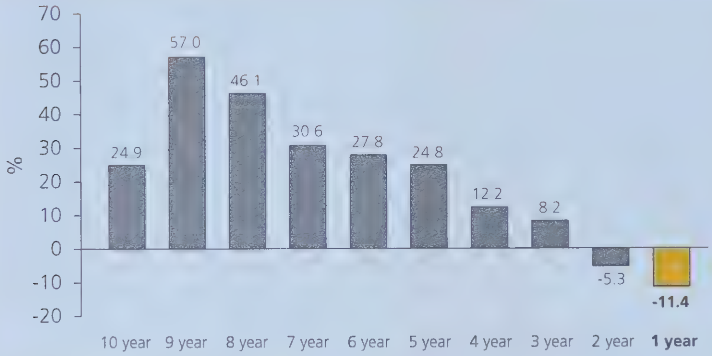
(3) The Reserve Life Indices (RLI) are based upon year-end proved plus probable reserves divided by the following year's proved and proved plus probable production volumes as determined in the independent reserve engineering reports.

historical performance

Total Return to Unitholders

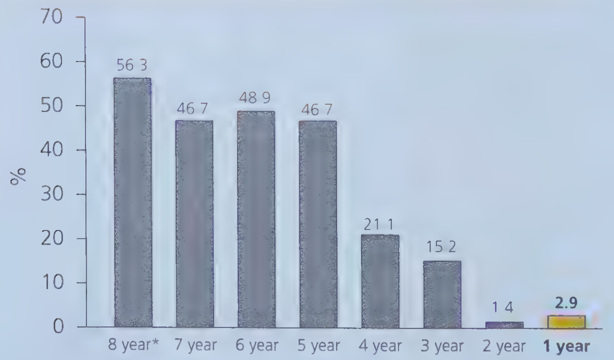
Calculated using unit prices at December 31 plus or minus capital appreciation or depreciation and the total cash distributions paid during the period.

Total Return per year – CDN$ (January 1 – December 31)

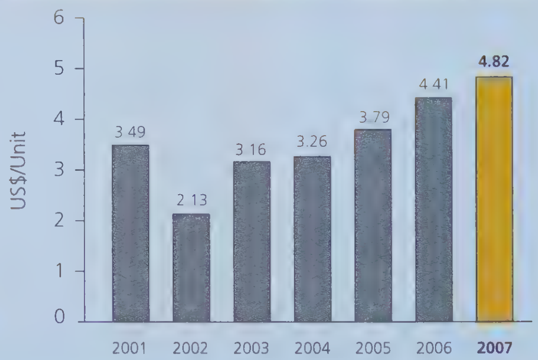


Cash Distributions Paid to Unitholders – CDN$

Total return per year – US$ (January I – December 31)



Cash Distributions Paid to Unitholders – US$



*using a starting date of November 17, 2000 – the first day of trading for Enerplus on the NYSE

Distributions to U.S. unitholders are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax. As Enerplus became listed on the NYSE in November of 2000, returns and cash distributions paid in U.S. dollars are reflected for all subsequent years only.

trust unit trading information

Toronto Stock Exchange 10 Year Trading Summary

CDN$	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
High	**53.70**	66.00	58.55	44.54	40.72	29.00	32.86	24.60	19.20	25.50
Low	**38.00**	43.86	40.00	32.73	25.82	22.85	22.00	15.60	12.60	12.00
Close	**39.87**	50.68	55.86	43.60	39.35	28.05	24.75	22.90	16.32	12.96
Volume (000's)	**96,898**	82,120	62,278	52,821	51,800	37,492	29,466	10,214	7,322	8,230

New York Stock Exchange Trading Summary

Enerplus Resources Fund began trading on the New York Stock Exchange on November 17, 2000.

US$	2007	2006	2005	2004	2003	2002	2001	2000
High	**50.75**	59.45	50.29	36.44	31.20	19.08	23.50	15.25
Low	**38.06**	38.50	32.00	23.65	17.06	14.30	13.79	14.69
Close	**40.05**	43.61	47.98	36.31	30.44	17.75	15.56	15.25
Volume (000's)	**54,192**	81,677	70,454	67,570	60,624	31,350	19,740	121

distribution reinvestment and unit purchase plan

Enerplus Resources Fund offers a convenient method for Canadian residents to reinvest cash distributions or invest additional funds into new trust units with the Distribution Reinvestment and Unit Purchase Plan ("the Plan").

Benefits of the Plan include:

- Existing unitholders can purchase new units of the Fund each month by automatically reinvesting cash distributions.
- Participants receive a 5% discount off the purchase price when reinvesting cash distributions.
- Current unitholders can also make optional cash payments each month to purchase additional units. The optional cash payments can be a minimum of $250 up to a maximum of $5,000 or the amount of cash distributions received each month.
- No commissions, service charges or brokerage fees are payable in conjunction with the Plan.

If your units are held through a broker, investment dealer or other financial intermediary, you must direct that company to enroll your units into the Plan.

To obtain more information, please contact our Investor Relations Department at 1-800-319-6462; in Calgary at (403) 298-2200; by fax at (403) 298-2211; or by email at investorrelations@enerplus.com. Information on the Plan is also available on our website at www.enerplus.com.

2007 income tax information

Information for Canadian Residents (CDN$ per Unit)

The following table outlines the breakdown of cash distributions per unit paid by Enerplus Resources Fund for the period February 20, 2007 to January 20, 2008 for Canadian income tax purposes.

Record Date	Payment Date	Total Distribution Paid	Taxable Other Income	Taxable Eligible Dividend	Return of Capital Amount
Feb 10, 2007	Feb 20, 2007	$0.42	$0.410086	$0	$0.009914
Mar 10, 2007	Mar 20, 2007	0.42	0.410086	0	0.009914
Apr 10, 2007	Apr 20, 2007	0.42	0.410086	0	0.009914
May 10, 2007	May 20, 2007	0.42	0.410086	0	0.009914
Jun 10, 2007	Jun 20, 2007	0.42	0.410086	0	0.009914
Jul 10, 2007	Jul 20, 2007	0.42	0.410086	0	0.009914
Aug 10, 2007	Aug 20, 2007	0.42	0.410086	0	0.009914
Sep 10, 2007	Sep 20, 2007	0.42	0.410086	0	0.009914
Oct 10, 2007	Oct 20, 2007	0.42	0.410086	0	0.009914
Nov 10, 2007	Nov 20, 2007	0.42	0.410086	0	0.009914
Dec 10, 2007	Dec 20, 2007	0.42	0.410087	0	0.009913
Dec 31, 2007	Jan 20, 2008	0.42	0.410087	0	0.009913
Total per unit		**$5.04**	**$4.921034**	**$0**	**$0.118966**

Information for United States Residents (US$ per Unit)

The following table outlines the breakdown of cash distributions per unit, prior to any amounts deducted for Canadian withholding tax, paid by Enerplus Resources Fund for the period January 20, 2007 to December 20, 2007 for units held through a broker or other intermediary. The amounts shown on the schedule are in U.S. dollars as converted on the applicable payment dates.

Record Date	Payment Date	Distribution Paid CDN$	Exchange Rate	Distribution Paid US$	Taxable Qualified Dividend US$	Non-Taxable Return of Capital US$
Dec 31, 2006	Jan 20, 2007	$0.42	0.849257	$0.356688	$0.331923	$0.024765
Feb 10, 2007	Feb 20, 2007	0.42	0.854482	0.358882	0.333965	0.024917
Mar 10, 2007	Mar 20, 2007	0.42	0.850340	0.357143	0.332347	0.024796
Apr 10, 2007	Apr 20, 2007	0.42	0.886053	0.372142	0.346304	0.025838
May 10, 2007	May 20, 2007	0.42	0.920132	0.386455	0.359624	0.026831
Jun 10, 2007	Jun 20, 2007	0.42	0.935628	0.392964	0.365681	0.027283
Jul 10, 2007	Jul 20, 2007	0.42	0.957029	0.401952	0.374045	0.027907
Aug 10, 2007	Aug 20, 2007	0.42	0.942151	0.395703	0.368230	0.027473
Sep 10, 2007	Sep 20, 2007	0.42	0.987849	0.414897	0.386091	0.028806
Oct 10, 2007	Oct 20, 2007	0.42	1.018537	0.427786	0.398085	0.029701
Nov 10, 2007	Nov 20, 2007	0.42	1.014404	0.426050	0.396470	0.029580
Dec 10, 2007	Dec 20, 2007	0.42	1.001001	0.420420	0.391230	0.029190
Total per unit		**$5.04**		**$4.711082**	**$4.383995**	**$0.327087**

abbreviations

In accordance with Canadian practice, production volumes, resource volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. All reserve figures are calculated based upon company interest reserves using forecast prices and costs. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Readers are also urged to review our Annual Information Form for full NI 51-101 compliant reserve and resource disclosure.

AECO	A reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
AOCI	accumulated other comprehensive income
API	American Petroleum Institute
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
BOE(s)/day	barrel of oil equivalent per day (6 Mcf of gas:1 BOE)
CBM	coalbed methane, otherwise known as natural gas from coal – NGC
COGPE	Canadian oil and gas property expense
CAPP	Canadian Association of Petroleum Producers
CTA	cumulative translation adjustment
EDGAR	Electronic Data Gathering, Analysis and Retrieval system
F&D Costs	finding and development costs
FD&A Costs	finding, development and acquisition costs
FDC	future development capital
GLJ	GLJ Petroleum Consultants Ltd., an external, independent third party engineering firm
GORR	gross overriding royalty
HH	"Henry Hub" A reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract
M&A	mergers and acquisitions

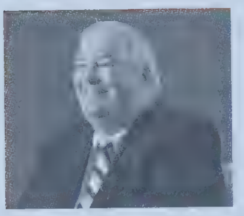
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf/day	million cubic feet per day
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NI 51-101	National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory authorities (pertaining to reserve reporting in Canada)
NYSE	New York Stock Exchange
OCI	other comprehensive income
OOIP	original oil in place
P+P Reserves	proved plus probable reserves
PDP Reserves	proved developed producing reserves
RLI	reserve life index
SAGD	steam assisted gravity drainage
SEDAR	System for Electronic Document Analysis and Retrieval
Sproule	Sproule Associates Limited, an external, independent third party engineering firm
Total	Total E&P Canada Ltd., operator of the Joslyn oil sands lease
TSX	Toronto Stock Exchange
WI	percentage working interest ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

definitions

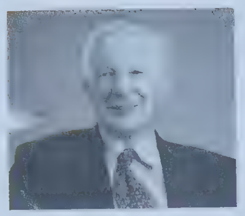
Bitumen/Oil Sands	A highly viscous oil which is too thick to flow in its native state and which cannot be produced without altering its viscosity. The density of bitumen is generally less than 10 degrees API.
BOE	Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
F&D Costs	Finding and development costs. Calculated as total capital expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserve additions (proved and/or proved plus probable). It is a measure of the effectiveness of a company's capital program.
FD&A Costs	Finding, development and acquisition costs. Calculated as total capital expenditures and net acquisitions, including changes in future development capital, divided by reserve additions (proved and/or proved plus probable). It is a measure of a company's ability to add reserves in a cost effective manner.
Future Development Capital	Future Development Capital is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, and capital cost estimate revisions.
NGLs	Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.
Oil, heavy	Oil with a density between 10 to 22.3 degrees API or where a royalty regime exists specific to heavy oil, it is defined based upon that royalty regime.
Oil, light & medium	Oil that has a density of 22.3 degrees API or higher.
Operating Income	Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.
Production, gross	Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.
Reserve Life Index, Proved	Calculated as proved reserves at year-end divided by the following year's estimate proved production volumes as determined by the independent reserve engineering report for 2003 and forward, and management's estimate for all prior years.
Reserve Life Index, Proved plus Probable	Calculated as proved plus probable reserves at year-end (established reserves for years 2002 and prior) divided by the following year's estimated proved plus probable production volumes as determined by the independent reserve engineering report for 2003 and forward and management's estimate for all prior years.
Reserves, Company Interest	Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus. Unless otherwise stated, reserve volumes utilized in any discussions or calculations are company interest reserves. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers.

Reserves, Gross	Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.
Reserves, Net	Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.
Reserves, Probable	Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
Reserves, Proved	Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
Reserves, Proved Developed Non-Producing	Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
Reserves, Proved Developed Producing	Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
Reserves, Proved Undeveloped	Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.
SAGD	Steam assisted gravity drainage, an in situ production process used to recover bitumen from oil sands.
Total Return	Calculated using the change in the trust unit price from the start of the period (including any capital appreciation or depreciation) and the total cash distributions paid during the period divided by the starting unit price.

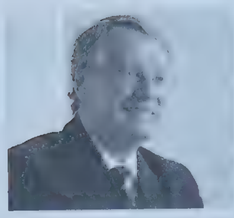
board of directors



Douglas R. Martin[1,2]
President
Charles Avenue Capital Corp.
Calgary, Alberta

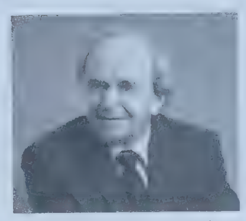


Edwin V. Dodge[3,9,11]
Corporate Director
Vancouver, British Columbia



Robert B. Hodgins
Corporate Director
Calgary, Alberta

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund
Calgary, Alberta



Robert L. Normand[6,9]
Corporate Director
Rosemere, Québec

David O'Brien
Corporate Director
Calgary, Alberta

Glen D. Roane[5,10]
Corporate Director
Canmore, Alberta

W. C. (Mike) Seth[3,7]
President
Seth Consultants Ltd.
Okotoks, Alberta

Donald T. West[7,12]
Corporate Director
Calgary, Alberta

Harry B. Wheeler[5,8]
President
Colchester Investments Ltd.
Calgary, Alberta

Clayton Woitas
Corporate Director
Calgary, Alberta

Robert L. Zorich[4,11]
Managing Director
EnCap Investments L.P.
Houston, Texas

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Environment, Health & Safety Committee
(12) Chairman of the Environment, Health & Safety Committee

officers

Gordon J. Kerr
President & Chief Executive Officer

Garry A. Tanner
Executive Vice President & Chief Operating Officer

Ian C. Dundas
Senior Vice President, Business Development

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Investor Relations & Corporate Communications

Ray Daniels
Vice President, Oil Sands

Rodney D. Gray
Vice President, Finance

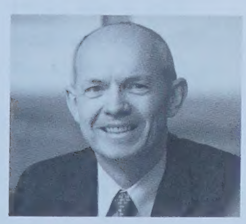
Larry P. Hammond
Vice President, Operations

Lyonel G. Kawa
Vice President, Information Services

Jennifer F. Koury
Vice President, Corporate Services

Eric G. Le Dain
Vice President, Marketing

David A. McCoy
Vice President, General Counsel & Corporate Secretary



Daniel M. Stevens
Vice President, Development Services

Wayne G. Ford
Controller, Operations

Jodine J. Jenson Labrie
Controller, Finance

corporate information

Operating Entities Owned by
Enerplus Resources Fund

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Oil & Gas Ltd.
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Transfer Agent
CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1.800.387.0825
Email: inquiries@cibcmellon.com

Co-Transfer Agent
Mellon Investor Services L.L.C.
Ridgefield, New Jersey

Independent Reserve Engineers
Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
New York Stock Exchange: ERF
Toronto Stock Exchange: ERF.un

Head Office
The Dome Tower
3000, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Telephone: 403.298.2200
Toll free: 1.800.319.6462
Fax: 403.298.2211
Email: investorrelations@enerplus.com

U.S. Office
Wells Fargo Center
1300, 1700 Lincoln Street
Denver, Colorado 80203

Telephone: 720.279.5500
Fax: 720.279.5550

corporate information

Enerplus Internet Site

Enerplus Resources Fund has a comprehensive website that provides investors with an immediate source of all public information. Information that can found at www.enerplus.com includes:

- Unit Trading Data
- Annual and Quarterly Reports
- Tax Information
- News Releases
- Recent Presentations
- 15 Minute Delayed Stock Quote
- Historical Distributions
- Distribution Reinvestment and Unit Purchase Plan
- Adjusted Cost Base Calculator
- Operational Information
- Corporate Governance Practices and Charters
- Whistleblower Policy
- Important Dates and Events
- Links to SEDAR and EDGAR filings
- Other relevant information pertaining to Enerplus Resources Fund

Annual General & Special Meeting

Unitholders are encouraged to attend the Annual General & Special Meeting being held on:

Friday, May 9, 2008
10:30 am, mountain daylight time at
The Metropolitan Centre
333 – 4th Avenue S.W.
Calgary, Alberta

07

FINANCIAL SUMMARY

THE ENERGY OF

enerPLUS

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

www.enerplus.com

Tel 403.298.2200
Toll Free 1.800.319.6462
Fax 403.298.2211
investorrelations@enerplus.com

ERF LISTED NYSE

ERF.UN LISTED TSX